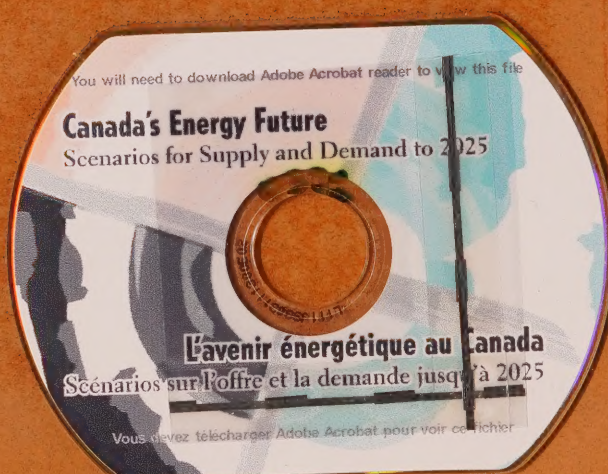
National Energy Board
Office national de l'énergie

Canadian Energy

SUPPLY AND DEMAND to 2025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Foreword

The National Energy Board (NEB or the Board) was created by an Act of Parliament in 1959. The Board's regulatory powers under the National Energy Board Act (the Act) include the authorization of exports of oil, gas and electricity; the authorization of the construction of interprovincial and international oil, gas and commodities pipelines and international power lines; the setting of just and reasonable tolls for pipelines under federal jurisdiction; and the regulation of oil and gas activities on Canada lands in the north. The Act also requires that the Board keep under review the outlook for Canadian supply of all major energy commodities including electricity, oil and natural gas and their by-products, and the demand for Canadian energy both domestically and abroad.

Since its inception, the Board has prepared and maintained projections of energy supply and requirements and has, from time to time, published its findings beginning with the first long-term outlook in 1967. In a July 1987 decision, the Board adopted the Market-Based Procedure[1] (MBP), as a replacement for the reserves surplus test, for regulating natural gas exports. At that time, the Board indicated its intention to continue to publish the *Canadian Energy Supply and Demand* reports as one component of ongoing monitoring under the MBP. The last supply and demand report was issued in 1994.

The objectives of these reports are:

- To provide a comprehensive "all energy" market analysis and outlook to serve as a standard of reference for all parties interested in Canadian energy issues and trends.
- To provide a framework for public discussion on emerging energy issues of national importance.
- To monitor the prospects for the supply, demand and price of natural gas in Canada pursuant to the MBP.

In preparing the *Canadian Energy Supply and Demand* reports, the Board has sought the views of Canadians interested in energy matters. In the late 1970s and early 1980s, external views were obtained through written submissions and public hearings. From 1984 to 1994, views were obtained on an informal basis and were not subject to public hearings. For this report, the Board has adopted a formal consultative process involving two rounds of public workshops held in eight Canadian cities.

The objective of the workshops was to provide members of the public an opportunity to comment on the Board's analysis. The first round, held in April 1998, discussed the major assumptions, the analytical approach, potential issues and the report format. The second series of workshops was held in February 1999 to discuss the preliminary results. Written comments for both rounds were invited.[2] Additionally, Board staff consulted with many sectors of the energy community to complement its in-house expertise.

The NEB greatly appreciates the comments and interchange of views during the consultations and would like to thank all those who contributed their time and expertise. The Board considered all comments and has incorporated some of the views of participants in the analysis. Sensitivity analyses were developed to reflect the divergence of opinion expressed during the consultations.

A number of parties have raised concerns over the use of *Canadian Energy Supply and Demand* reports in the Board's regulatory proceedings and questioned whether these reports are an official reflection of its views. The Board wishes to clarify its views in this regard:

> Material contained in these reports may be used as part of the evidentiary record, in particular regulatory proceedings. Any party could rely on such material, just as it could rely on any

1 The Market-Based Procedure was adopted after the hearing GHR-1-87 in July 1987

2 A list of parties who sent written submissions is provided in Appendix 1

public document. In such a case, the material is in effect adopted by the party introducing it.

In this respect, there has been no change in the Board's views regarding the way in which the reports may be used in the regulatory process.

As part of the MBP, the Board publishes *Natural Gas Market Assessments* (NGMA) which address current and near-term developments. The *Canadian Energy Supply and Demand* reports address longer-term issues. In the future, as a result of the integration of energy markets, the Board will issue *Energy Market Assessments* (EMA). EMA will provide analyses of the major energy commodities, including natural gas. The *Canadian Energy Supply and Demand* reports are an integral part of this EMA program.

There are some changes in this report compared to earlier editions. For example, it does not contain an *Export Impact Assessment*, although it is anticipated that interested parties may use the data and analysis in this report to develop their own natural gas export impact assessments. Also, the various appendices will be available electronically to facilitate analysis and research on Canadian energy matters.

Finally, the Board advises that the purpose of the *Canadian Energy Supply and Demand* reports is to provide a range of energy supply and demand projections for the information of the public. They should not be perceived as recommendations to the Minister of Natural Resources, nor should they be viewed as expressing policy on energy matters.

CHAPTER 1

Trends and Issues

The only certain thing about the future is that it will surprise even those who have seen furthest into it.

E. J. Hobsbawm

The observation of Mr. Hobsbawm is particularly applicable in the case of the energy sector; there are a number of major uncertainties, including oil and gas prices and government policies. This chapter highlights the main trends and issues that arise from the Board's long-term energy outlook for Canada. In conducting this analysis, the Board relies on the underlying principle that market forces will govern the choices made by energy producers and consumers. In this framework, only the impact of energy policies that are in place or have been announced is included. A main theme pursued throughout the analysis is the possible impact of technology on the supply and demand of energy over the next three decades.

ASSUMPTIONS AND CASES

The Board's analysis is based on a world oil price of US$(1997)18 per barrel throughout the projection. It is recognized that oil prices will be volatile; therefore, two oil price sensitivities have been analyzed: US$14 and US$22 per barrel. These prices could be viewed as the upper and lower bounds of a sustainable price range.

The outlook for Canadian economic growth could be characterized as "business as usual." After annual GDP growth of almost 3 percent to 2005, growth decelerates to about 2 percent per year to 2025. The slower growth over time is largely associated with the ageing of the Canadian population and associated declining growth in the labour force.

To capture a range of plausible outcomes, the Board developed two cases. Case 1 assumes low cost energy supply and current trends in demand. In other words, the supply of energy becomes cheaper through technological innovation, while the demand for energy reflects recent trends in energy efficiency. Case 2 assumes current trends in supply and accelerated demand efficiency. In other words, technological innovation in the supply of energy reflects recent trends, while energy demand is reduced through more efficient applications.

In addition, a series of sensitivity analyses were developed to analyze specific issues. The major analysis focuses on the use of alternative technologies and renewable fuels (A&R Sensitivity). Other areas examined are: world crude oil prices; early nuclear retirements in the electricity generation sector; and reduced constraints on electricity transmission.

DEMAND

Total end use energy demand is expected to increase over the projection period, but at a slower pace than the growth of GDP. In Case 1, growth in demand averages 1.4 percent per year, while it averages 0.9 percent per year in Case 2. By the end of the projection period, demand in Case 1 reaches 12 588 PJ, compared to 8 389 PJ in 1997; in Case 2 it reaches 10 953 PJ, a difference of about 13 percent.

A variety of factors are expected to reduce the rate of growth in energy demand. In the residential sector, these include improvements in furnace efficiency and the lower energy requirements of an ageing population. Commercial sector demand will be influenced by the penetration of more efficient equipment and better conservation practices. In the industrial sector, demand growth will be modified by the adoption of leading-edge technologies and by a structural shift toward industries that require less energy.

In the road transportation sector, especially for passenger vehicles, alternative technologies could have a noticeable impact. The penetration of alternative vehicles, such as hybrid-electric vehicles and fuel-cell vehicles, is projected to reduce energy consumption in all cases. In the A&R Sensitivity, fuel-cell vehicles are projected to operate on cleaner-burning methanol.

Hog fuel, pulping liquor and wood currently account for most of the consumption of renewable fuels. In the A&R Sensitivity, greater penetration of

these fuels and of solar energy is projected to increase the market share of renewable fuels.

ELECTRICITY

In general, restructuring in the electricity sector will likely lead to reduced electricity prices in the near term. However, as fuel prices rise, so will those of electricity. Restructuring will also lead to the entry of new power suppliers and change the fuel mix of generation.

Electricity generation reaches 838 TW.h in Case 1 and 744 TW.h in Case 2 from current levels of 551 TW.h. Continued growth in domestic electricity demand and export opportunities will require additional generating capacity, which will mostly be hydro and gas-fired. Combined-cycle gas technology, located close to load centres, appears to be the preferred option for new generation.

Hydroelectricity will remain predominant, although the share of gas in total generation is expected to increase markedly. The shares of coal and oil-fired generation are expected to decline. Exports are projected to remain close to historical levels, due mainly to declining surpluses and the trend toward distributed generation.

The construction of a high voltage transmission line connecting Labrador to Newfoundland would have the effect of displacing thermal generation on the island and increasing hydro generation in Québec. Removing transmission constraints would increase hydroelectricity generation in Manitoba thereby reducing Ontario's requirement for new thermal generation.

Higher penetration of alternative technologies and renewable fuels is expected to require more support and stimulus than current market conditions offer. Nevertheless, wind generation is expected to increase in both cases. In the A&R Sensitivity, the growth in wind generation is stronger and is combined with growth in biomass generation. In addition, alternative technologies, such as integrated gasification combined cycle plants, are projected to replace conventional coal generation.

NATURAL GAS

Natural gas production increases from 15 Bcf/d in 1997 to 27 Bcf/d in Case 1 in 2025. In Case 2, it peaks at 23 Bcf/d in 2018 and then declines to 21 Bcf/d. Deliverability from conventional gas in Canada is highly dependent on the level of undiscovered resources. Furthermore, supply from western Canada will depend on a shift in drilling strategies to the western part of the basin, away from the shallow gas areas that have traditionally been dominant. By 2010, it will also depend on the development of technologies to extract coal bed methane. The Mackenzie Delta region is expected to become a gas supply source after 2015 in Case 2.

Exports are expected to rise. Major pipeline expansions appear to be needed from western Canada to the U.S. Midwest and from the Scotian Shelf to the U.S. Northeast. In the event of much stronger gas demand due to early nuclear plants retirements in Ontario and the U.S., gas prices could increase by about 18 percent by 2025. This increase could be even greater if future U.S. gas demand is as robust as some have suggested.

Regional supply patterns in the U.S. are projected to change. Both the Gulf of Mexico and the Rocky Mountain regions are expected to increase production, whereas the Permian and Anadarko basins are projected to decline.

NATURAL GAS LIQUIDS

In general, there will be a surplus of NGL relative to domestic requirements, particularly for propane and butanes. Domestic demand for ethane is projected to grow as a result of expansions to the ethylene manufacturing industry. However, late in the projection period, NGL production declines as conventional natural gas is replaced with coal bed methane, which does not contain NGL. In both cases, natural gas prices rise relative to those of oil, which could have a negative impact on the levels of ethane extraction.

CRUDE OIL

In Case 1, the supply of crude oil and equivalent rises from 331 100 m3/d in 1997 to 500 000 m3/d by 2007 and then declines to 410 000 m3/d by 2025. In Case 2, it peaks at 440 000 m3/d in 2007 before declining to 330 000 m3/d by 2025.

The application of new technology has been an increasingly important element of the Canadian crude oil industry. The projections of oil supply assume that an aggressive approach to research and technological innovation will be maintained.

The projected levels of supply for conventional light and heavy crude oil in the WCSB would not be possible without significant technological advances in finding and developing resources, including advances in enhanced oil recovery techniques. Even so, the limited remaining recoverable resources will result in declining supply. This decline is partially offset by the increasing importance of the oil sands and of the east coast offshore area.

Oil sands production is expected to increase by three to four times above current levels by 2025. This growth will require significant advances in the areas of extraction, transportation and processing. Similarly, the supply projections for the east coast offshore area are dependent on technological innovation, such as sub-sea infrastructure design that would allow the exploitation of smaller satellite pools.

Any potential shortfall in pentanes plus supply for diluent requirement is assumed to be alleviated by technological advances in transportation, or upgrading, or by the use of alternate blending agents. The projected volumes of oil sands upgraded crude oil and blended heavy oil are in excess of estimated domestic requirements and historical export volumes. In Case 1 and Case 2, growing demand in the U.S. markets for these types of crude oil is expected to absorb these excess volumes.

COAL

Due to extensive world-wide resources of coal, prices are expected to remain low relative to other fuels. Coal will continue to make a significant contribution to Canadians energy supply. Technological advances in the way coal is used in electricity generation are anticipated, particularly in the A&R Sensitivity.

EMISSIONS OF GREENHOUSE GASES

The emissions of GHG are expected to increase in all cases. The increase is most rapid to 2010, reaching 702 Mt per year for Case 1 (a 24 percent increase from 1997), 656 Mt in Case 2 (a 14 percent increase) and 650 Mt for the A&R Sensitivity (a 14 percent increase).

By 2025, emissions are projected to be 811 Mt in Case 1 (a 44 percent increase from 1997), 683 Mt in Case 2 (a 21 percent increase) and 654 Mt in the A&R Sensitivity (a 16 percent increase).

The transportation and fossil fuel production sectors are the principal sources of GHG emissions. The introduction of hybrid electric and fuel cell vehicles could help reduce GHG emissions in the transportation sector. In the A&R Sensitivity, a shift towards renewable energy sources, particularly in electricity generation, results in a modest reduction in GHG emissions.

CHAPTER 2

Assumptions and Cases

2.1 INTRODUCTION

This chapter presents an overview of the major assumptions used in the Board's long-term energy outlook, including world oil prices, main economic indicators, as well as Canadian demographic and structural trends.[1] In addition, there is a description of the two main cases that form the basis of the outlook and a presentation of the sensitivity analysis.

2.2 WORLD OIL PRICES

The factors governing oil price determination are generally well known:

- World economic growth and oil demand
- Non-OPEC oil production
- OPEC's ability to manage its low-cost surplus production capacity

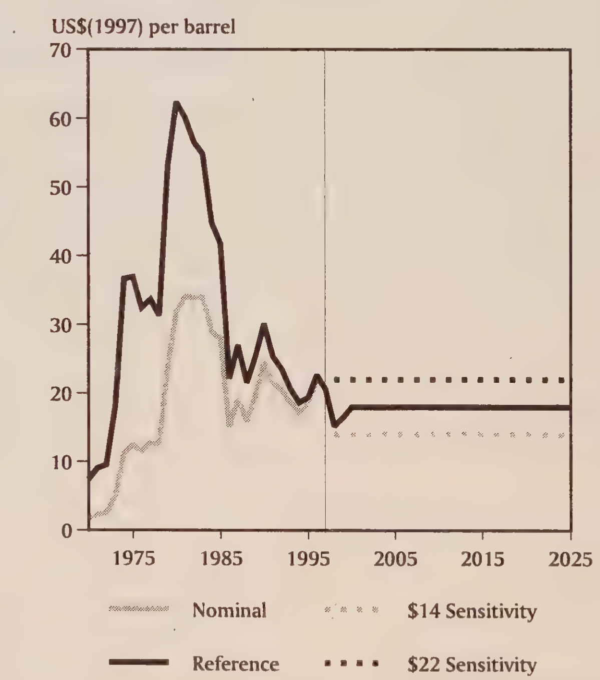
The interplay of these factors causes price forecasting to be hazardous. In the short term, substantial low-cost capacity remains shut-in and it tends to be concentrated in a few countries in the Middle East. Oil prices are thus vulnerable to substantial volatility due to market imbalances and political events. In the long term, the outlook is complicated by factors as varied as the sustainability of economic growth in the newly-industrialized countries and the impact of technology on future oil supplies and substitutable energy forms. All this is apart from the uncertainty associated with potential international action on environmental matters, specifically the concern with climate change, and the impact this may have on oil markets.

In this report, the Board has adopted the assumption that oil prices will remain constant at US$(1997)18 per barrel (West Texas Intermediate [WTI] at Cushing, Oklahoma) (Figure 2.1). This implies that over the 25 year study period, world demand will continue to be met at prices approximating those of the mid-1990s. To maintain that price level requires some discipline on the part of OPEC in setting and observing production quotas, at least in the near term.

A constant oil price over the long term runs counter to a more traditional view that increasing exploitation of the world's reserves will result in increasing costs. The constant outlook means that technological progress will enable world oil supplies to accommodate increases in demand at constant costs. There continues to be evidence of this in the sustained increase in North Sea production and in the progress of heavy oil technologies in both Canada and Venezuela that have substantially reduced development and production costs. More generally, production in the non-OPEC countries has continued to increase in recent years, even in an environment of relatively low and volatile prices.

Within the time period of this analysis, it is also possible that a combination of technologies emerges to reduce or moderate the increase in crude oil demand,

Figure 2.1
World Oil Price – WTI at Cushing



1 Oil price data and national and regional economic indicators are available in *Appendix 2: Assumptions and Cases.*

effectively limiting price increases. Examples include: accelerated exploitation of the world's gas reserves for use in electricity generation; the large-scale production of liquid transportation fuels directly from natural gas; and the development and widespread adoption of fuel cell technology.

During the Board's consultations, there was a general consensus that US$18 was a reasonable assumption for the longer term. However, some participants suggested that a combination of factors could keep prices lower than US$18 for an extended period. Another view was that a price below US$18 for several years would cause demand to increase but force supply in higher-cost areas to decline, thus setting the stage for a sharp price increase in later years.

To address long-term oil price uncertainty, sensitivity analyses were undertaken at US$14 and US$22 per barrel. Based on the Board's consultations, these prices might be regarded as the bounds of a sustainable range. Below US$14, industry supply activity declines and demand increases, thus creating upward pressure on prices. Above US$22, oil supply increases, OPEC has difficulty in managing the surplus, and prices decline.

The Board's pricing assumptions tend to cover the range of other recent long-term price outlooks, such as those produced by the U.S. Department of Energy/Energy Information Administration (EIA), Petroleum Economics Limited (PEL) and Petroleum Industry Research Associates (PIRA) (Figure 2.2). The reference case in the EIA's Annual Energy Outlook 1999 assumes that oil prices will increase from US$15 per barrel in 2000 to US$19 in 2010 and US$23 in 2020. PEL's outlook is in the US$14 to US$15 range during the period 2010-2015. PIRA's outlook foresees US$17 in 2005 and US$19 in 2010.

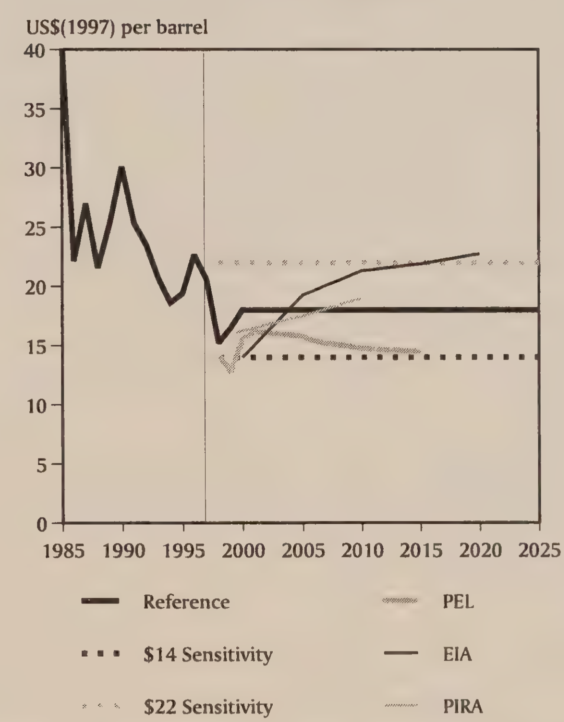
2.3 ECONOMIC ASSUMPTIONS

A projection of Canadian economic growth is essential to the energy outlook because the demand for energy is dependent on overall growth, demographic trends and structural changes in the economy. The economic outlook underpinning this report might be best described as a "business as usual" projection that assumes no fundamental changes to government policies and uses best judgment with respect to the impact of key external factors, such as U.S. economic growth and other developments affecting international trade.[2]

Over the next five to six years, growth in Gross Domestic Product (GDP) is expected to be relatively strong averaging about three percent per year (Table 2.1), reflecting continued robust growth in the U.S. and a gradual economic recovery in south-east Asia and Japan. Recent Canadian monetary and fiscal policies are expected to continue: inflation is maintained at around 2 percent per year and fiscal balances show steady improvement. In this environment, the Canadian dollar is projected to appreciate to US$0.74 by 2005, then gradually to US$0.79 by 2025.

Longer term, growth slows with the declining growth in the labour force and lower participation rates, both resulting from the ageing of the population. The average annual GDP growth will be just over two percent per year, somewhat below that of the past 20 years. With overall employment growing about one

Figure 2.2
World Oil Price Comparison



2 The economic outlook is based on Informetrica Limited's June 1998 Reference Case, modified to take into account comments obtained during the Round 1 Consultations and to reflect the Board's main assumptions on energy prices, production and exports.

percent per year, the implied annual productivity gain is also about one percent. It is recognized that growth in any year may differ from the trends presented in this economic outlook; however, short-term deviations have little impact on long-term energy projections and no attempt was made to predict such events.

A comparison of the Board's economic outlook with those of the Conference Board of Canada and Standard and Poor's/Data Resources Inc. (DRI) is presented in Table 2.2. The trends in economic growth for both the Conference Board and DRI are similar to the Board's, i.e., stronger growth in the 1997-2005 period, then moderating in the longer term. All three outlooks have relatively low inflation, in the range of two to three percent per year, and demonstrate significant appreciation of the Canadian dollar relative to the U.S. dollar.

Demographic Changes

In the Board's economic outlook, Canada's population is projected to increase to about 40 million by the year 2025 (Figure 2.3). The domestic fertility rate is assumed to remain below that required to maintain a stable or growing population; hence population growth is maintained by an increase in immigration. By the end of the period, annual immigration is assumed to be about 400 000 people per year, compared to 225 000 per year in the first half of the 1990s.

An important aspect of demographic changes is the ageing of the population. This phenomenon is represented in Figure 2.4 by the changes in three population age groups over time: negative or low growth in the "under15"; declining growth in the "15 to 64"; and increasing growth in the "65 and over." The latter trends include the effect of the maturing of the large "baby

Table 2.1
Main Economic Indicators
(average annual percent growth)

	1981-1997	1997-2005	2005-2015	2015-2025
Canada				
Real GDP	2.3	2.9	2.1	2.0
Population	1.2	0.9	0.9	1.0
Labour force	1.4	1.4	0.9	0.4
Employment	1.3	1.7	0.8	0.7
Unemployment rate[1]	9.1	7.6	8.5	7.5
Households	1.2	0.9	0.9	1.0
Inflation (CPI)	3.9	1.8	2.0	2.3
Cdn$ in U.S. funds[1]	0.72	0.74	0.77	0.79
U.S. real GDP	2.6	2.2	2.1	2.1
U.S. Inflation (CPI)	4.0	2.3	2.2	2.1
G7 real GDP (excl. Canada and U.S.)	2.7	2.5	2.7	2.8

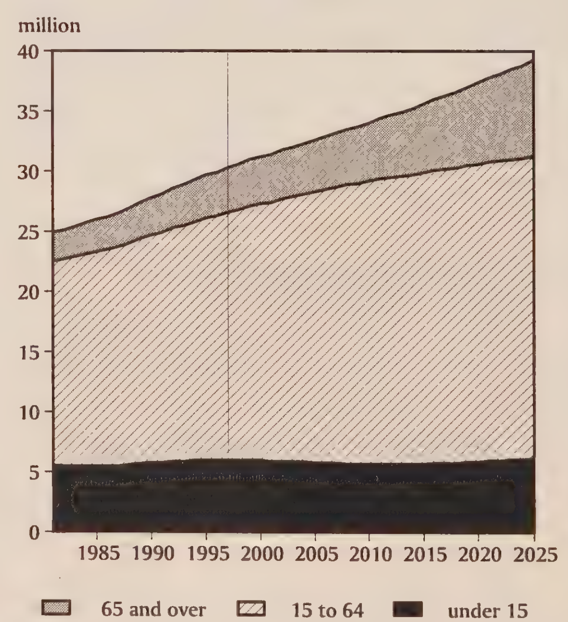
1 end of period

Table 2.2
Economic Indicators, Selected Comparisons

	1997-2005	2005-2015	2015-2025
GDP (average annual percent growth)			
NEB	2.9	2.1	2.0
Conference Board	2.8	2.3	2.2[1]
Standard and Poor's/DRI	3.2	2.4	1.6[1]
CPI (average annual percent growth)			
NEB	1.8	2.0	2.3
Conference Board	1.9	2.3	2.6[1]
Standard and Poor's/DRI	1.7	2.7	3.0[1]
Cdn dollar in US Funds (end of period)			
NEB	0.74	0.77	0.79
Conference Board	0.74	0.76	0.79[1]
Standard and Poor's/DRI	0.81	0.88	0.91[1]

1 to 2020

Figure 2.3
Population by Age Group



boom" generation (born between 1947 and 1966) which will approach or reach retirement by 2025.

The ageing of the population is a main contributor to the declining growth in the labour force, and hence, to slower economic growth. There are also some implications for energy demand, including

- Slower growth in new car sales and kilometres driven, because older people tend to drive less
- Higher demand for multiple unit housing, which may result in slower growth in residential demand
- Fewer people per household, which may result in a trend toward smaller homes or lower consumption per household

Economic Structure

The GDP outlook for five sectors is presented in Figure 2.5.[3]

Business-related services are expected to grow most rapidly, averaging three percent annually during the projection period. This sector includes communications, finance and insurance, transportation and professional services, all of which are key components of the "information economy." There is also strong growth in durables and investment goods, particularly in the near term. This sector includes the production of electronic equipment, transportation equipment, and construction and related services.

Consumer goods and services include wholesale and retail trade, accommodation, recreation and other personal expenditures. This sector increases in line with the total economy. The resource-based goods sector, which includes the forest industries, energy, mining and chemicals, grows at 1.9 percent per year.

The slowest growth is in government and social services, averaging 1.4 percent per year. Relatively strong growth in health services is offset by slow growth in education and other government services.

For its commercial and industrial energy demand analyses, the Board requires projections for "commercial GDP" and "industrial GDP." The former includes wholesale and retail trade, finance, insurance and public

Figure 2.4
Change in Population by Age Group

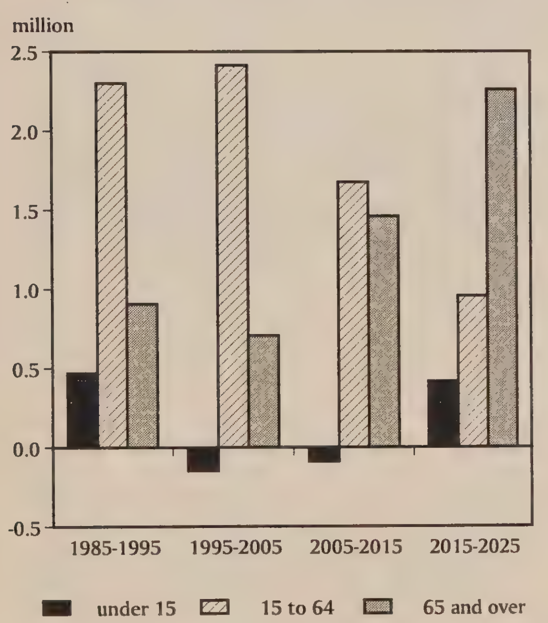
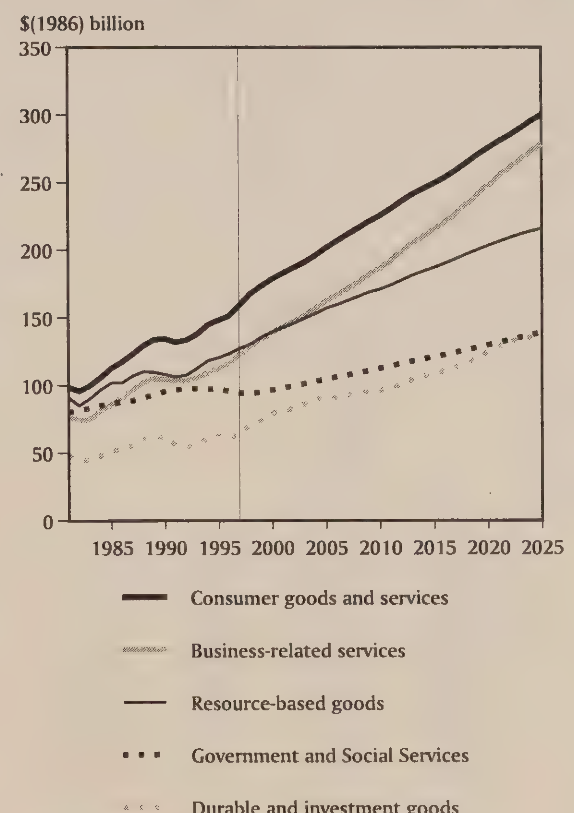


Figure 2.5
Canadian GDP by Sector



3 This disaggregation is provided by Informetrica Limited.

administration. The latter includes forestry, mining, manufacturing and construction.

The overall growth patterns tend to be similar (Figure 2.6) with both sectors growing faster until 2005 and then more slowly later in the projection period. However, during the entire projection period, growth in industrial GDP exceeds growth in commercial GDP by about 0.5 percent per year. The commercial sector has strong growth in business services, but relatively slow growth in government services. The industrial sector has stronger growth in chemicals, primary metals and some other manufacturing activities, but slower growth in the pulp and paper industry.

Provincial Economic Growth

In the near term (to 2005), economic growth by region varies substantially, because of the impact of large investments in specific projects or sectors and events that have varying regional impacts (Figure 2.7).

Energy investments stimulate growth in Alberta and the Atlantic region, particularly Newfoundland and Nova Scotia. The outlook for central Canada, including Québec, Ontario and Manitoba, is influenced by the exports to the U.S. of manufactured goods, and some resource-based goods. Saskatchewan's growth is supported by gains in agriculture and energy investment. B.C.'s lower growth in the near-term reflects the impact of the Asian economic slowdown.

In the long term (2005-2025), the occurrence of specific investments tends to be less certain as most identifiable projects are completed. Therefore, the differences between the provinces tend to be correlated with population trends. The population projection underlying this outlook assumes somewhat higher population growth in Ontario and western Canada, which leads to stronger growth in these regions.

Figure 2.6
Commercial and Industrial GDP Growth

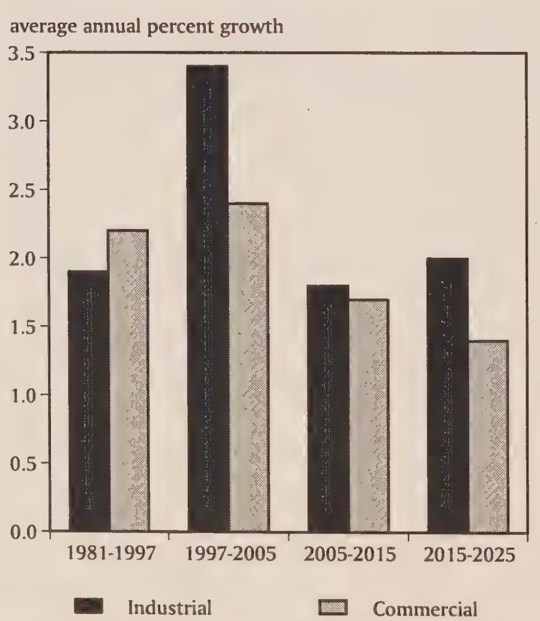
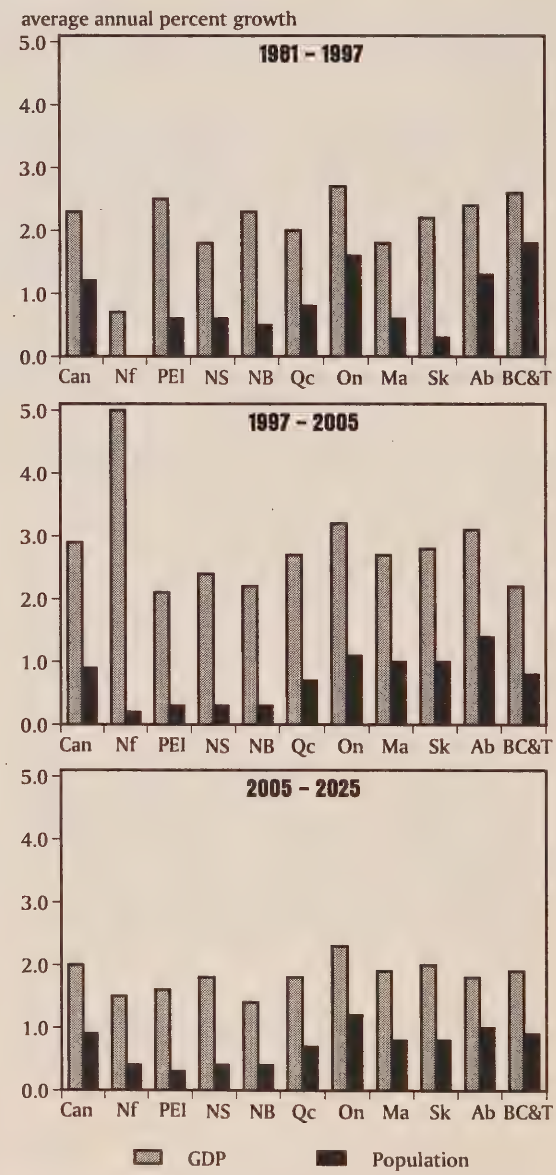


Figure 2.7
Provincial GDP and Population Growth



2.4 CASES

To produce meaningful long-term projections, the Board views a range of outcomes to be preferable to a single line or "base case." Therefore, two supply and two demand cases have been developed which, when combined, result in four possible outcomes.

The two supply cases are:

- Current Supply Trends (CST)
- Low Cost Supply (LCS)

In the CST Case, recent trends in energy supply are expected to continue. That is, technology improvements have a similar impact on costs and finding rates as in recent years. As a consequence, resource estimates tend to be lower than in the LCS Case. In the LCS Case, substantial improvements in finding rates and reduced costs lead to more resources being available at lower costs.

The two demand cases are:

- Current Demand Trends (CDT)
- Accelerated Demand Efficiency (ADE)

In the CDT Case, recent rates of technological developments in areas such as energy efficiency are expected to continue. Consumer preferences will also follow recent trends. The ADE Case anticipates that accelerated rates of technological development will lead to more efficient end-use applications. Changes in consumer preferences could also lead to lower energy consumption.

Conceptually, the four cases (two demand and two supply) are represented in Figure 2.8 by classic supply and demand curves. As prices rise, the quantity supplied increases along a given supply curve and the quantity demanded declines along a given demand curve.

The two supply curves represent the different cost conditions; at a given price level, more supply is available in the LCS Case, compared to the CST Case. The difference between the demand curves represents a change in consumer preferences and the recognition that demand savings are available, or feasible, at a given price level through new technologies; hence, demand is lower in the ADE Case than in the CDT Case.

In this stylized representation, there are four sets of equilibrium or market clearing volumes. The biggest range of market clearing volumes is created by combining CDT and LCS to form Case 1, at the high end, and by combining ADE and CST to form Case 2, at the low end. Neither of these cases is a "base case"; rather, they are proposed as the bounds of a plausible range of outcomes.

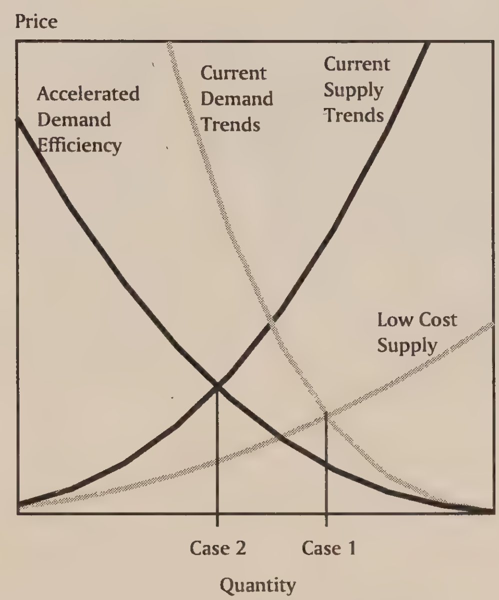
2.5 SENSITIVITY ANALYSES

Sensitivity analyses have been undertaken in three areas: oil prices; alternative technologies and renewable fuels, and electricity generation and transmission. Sensitivity analyses are less comprehensive than Case 1 and Case 2 because they focus on the impact of changes to key assumptions on specific areas of interest. They are developed either from Case 1 or Case 2 and only look at the impact on a few variables.

Oil Prices

Case 1 and Case 2 both assume oil prices to be $18US per barrel. Two oil price sensitivities assess the impact of lower and higher oil prices on Canadian oil supply, gas supply and gas prices. The $14 Sensitivity is based on Case 2 (Current Supply Trends) and the $22 Sensitivity is based on Case 1 (Low Cost Supply). The results are discussed in Chapter 5 and Chapter 7.

Figure 2.8
Supply and Demand Cases



Alternative Technologies and Renewable Fuels

The Alternative Technologies and Renewable Fuels Sensitivity (A&R Sensitivity) is primarily an energy demand sensitivity which was developed from Case 2. It is also an energy supply sensitivity in that more of the electricity consumed may be produced from alternative technologies or renewable fuels. The prospects for these technologies and fuels are examined in several end-use sectors and electricity generation. The analysis includes:

- Renewable energy forms such as solar energy, wind, small hydro and biomass
- Alternative vehicles such as gasoline-electric hybrids and methanol-powered fuel cell automobiles
- Diesel-powered automobiles
- Integrated coal gasification combined-cycle (IGCC) generation.

Results for the A&R Sensitivity appear in Chapter 3 and Chapter 4.

Electricity Generation

Two sensitivity analyses were undertaken, the Nuclear Generation Sensitivity and the Transmission Sensitivity.

The Nuclear Generation Sensitivity was developed from Case 2. It examines the impact of an increased demand for natural gas as the result of early nuclear plant retirements in Ontario and the U.S. This includes the impact on electricity generation in Ontario and the implications for Canadian natural gas supply, prices and exports. Results appear in Chapter 4 and Chapter 5.

The Transmission Sensitivity was developed from Case 1. It examines the impact on electricity generation and trade resulting from reduced constraints on interregional electricity transmission. Since most of the impact would be on the development of large-scale hydro projects it was developed for the eastern provinces, including Manitoba. Results appear in Chapter 4.

CHAPTER 3

Demand

3.1 INTRODUCTION

This chapter highlights the projected results for the Current Demand Trends Case (Case 1), the Accelerated Demand Efficiency Case (Case 2) and the Alternative Technologies and Renewable Fuels Sensitivity (A&R Sensitivity).[1] The demand for energy and the choice of fuels are driven by demographic, economic, technological, sociological and environmental factors. Some factors are assumed to be identical in all cases while others vary between cases. Differences and similarities are outlined below.

Factors common to Case 1, Case 2 and the A&R Sensitivity include:[2]

- demographic variables (e.g., number of households, population)
- macroeconomic variables (e.g., GDP, exchange rate, inflation, personal disposable income)
- weather-related variables (e.g., heating degree days)
- world oil prices

Factors that differ between Case 1 and Case 2 include:

- the rate of technological innovation
- the penetration rate of energy-efficient technologies
- the adoption rate of energy-efficient behaviours
- the prices of natural gas, electricity and coal

The A&R Sensitivity was developed from Case 2; hence, energy prices are the same for these two cases. The key difference between these two cases is the fuel mix in the following sectors:

- residential
- commercial
- industrial
- road transportation
- electricity generation (see Chapter 4)

1 Detailed results for Canada and by region are available in *Appendix 3: Demand*.

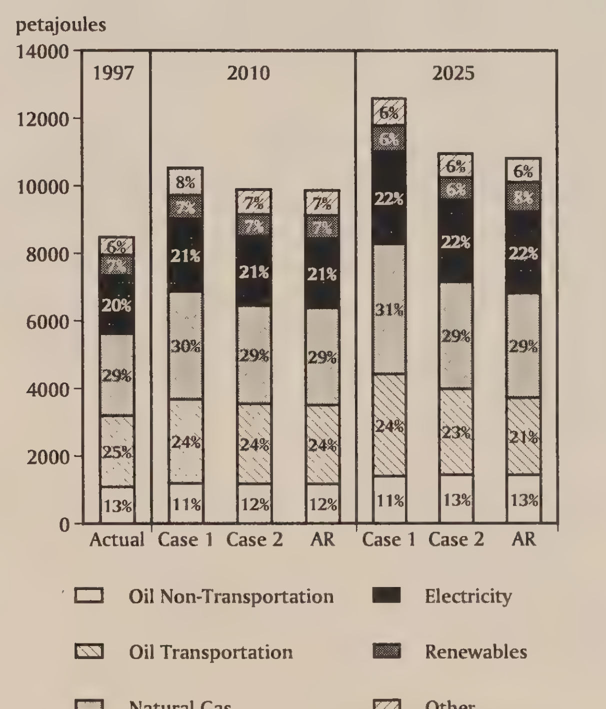
2 Some of these indicators are available in *Appendix 2: Assumptions and Cases*.

Many government and privately sponsored programs also influence energy consumption. The NEB did not evaluate the impact of specific programs, although the aggregate impact of programs is reflected in the results. While all cases considered existing and announced programs, their impact is assumed to be greater in Case 2 and the A&R Sensitivity than in Case 1.

3.2 TOTAL SECONDARY ENERGY DEMAND

Total Canadian secondary (or end use) demand was 8 482 petajoules (PJ) in 1997. In Case 1, it is projected to grow at an average of 1.4 percent per year to reach 12 588 PJ in 2025 (Figure 3.1). In Case 2, total demand is projected to grow at an average of 0.9 percent per year to reach 10 953 PJ in 2025. By 2025, the difference between Case 1 and Case 2 is about 15 percent. In

Figure 3.1
Total Secondary Energy by Fuel



the A&R Sensitivity, total demand is almost identical to Case 2.

In 1997, 38 percent of total secondary demand was met by oil products (gasoline, diesel, heavy fuel oil, light fuel oil, kerosene, aviation fuels and petroleum coke), 29 percent by natural gas, 20 percent by electricity, 7 percent by renewable fuels (pulping liquor, hog fuel, wood and solar energy) and 6 percent by other fuels (coal, coke, liquefied petroleum gases, ethane and steam).

The market share of oil products declines in all cases: it drops to 35 percent in Case 1, 36 percent in Case 2 and 34 percent in the A&R Sensitivity. The share of natural gas increases slightly to 31 percent in Case 1 while it remains nearly constant in Case 2 and in the A&R Sensitivity. In all cases, the share of electricity increases to approximately 22 percent. In Case 1 and Case 2, the share of renewable fuels declines to 6 percent, but it remains at 7 percent in the A&R Sensitivity. Finally, the combined share of all other fuels is fairly constant at just over 6 percent in Case 1 and Case 2 while it increases to 7 percent in the A&R Sensitivity.

In 1997, the industrial sector was the largest energy user in Canada with 34 percent of end use consumption. It was followed by transportation (25 percent), residential (19 percent), commercial (12 percent) and non-energy use of hydrocarbons (10 percent). In all cases, the relative share of each sector is projected to remain fairly stable.

An indicator of energy intensity for the overall economy is the amount of energy consumed per unit of real GDP (Figure 3.2). Between 1985 and 1997, overall energy intensity declined at an average of 0.6 percent per year. It is projected to decline at a somewhat faster pace in the projection period. In Case 1, it declines by 0.8 percent per year; in Case 2 and in the A&R Sensitivity, by 1.3 percent per year.

3.3 SECTORAL SECONDARY ENERGY DEMAND

This section examines end use energy demand for the following sectors: residential, commercial, industrial, road transportation, other transportation and non-energy use of hydrocarbons.

3.3.1 Residential Sector

Residential demand consists of energy consumed in all residential dwellings (i.e., single houses, semi-detached houses, apartments, townhouses, condominiums and mobile homes). In 1997, single detached houses accounted for about 55 percent of the housing stock and apartments for 32 percent. This sector also includes fuel used to operate farm equipment, but does not include fuels used for household vehicles.

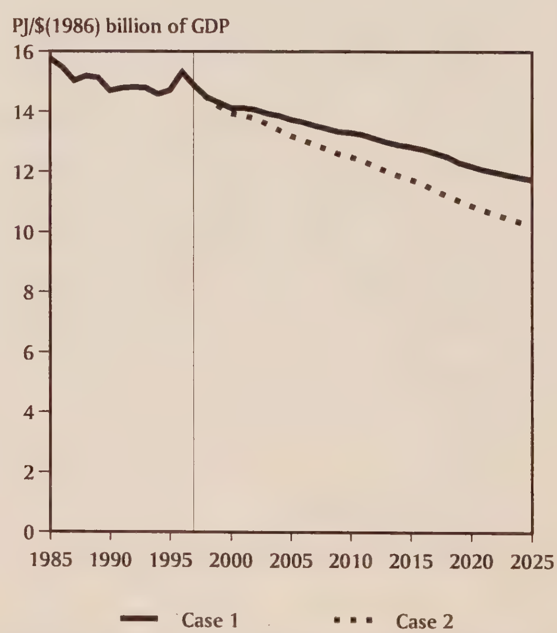
Energy is used for space and water heating, appliances, lighting and space cooling. Due to Canada's climate, space heating accounts for more than 60 percent of energy requirements. Key determinants of residential energy demand include the number of households and personal disposable income.

Residential Efficiency-Adjusted Energy Prices

Major fuels in the residential sector are natural gas, electricity and light fuel oil (LFO). Figure 3.3 presents the average Canadian efficiency-adjusted prices for Case 1 and Case 2. Prices in the A&R Sensitivity are assumed to be the same as in Case 2.

Electricity prices remain higher than those of natural gas and LFO in both cases. They tend to decline in the near term but rise longer term. In Case 2, they eventually exceed 1997 levels towards the end of the projection, when they are approximately 14 percent higher than in Case 1. The relatively higher electricity prices are expected to have little impact on electricity demand

Figure 3.2
Overall Energy Intensity



because no convenient and economical alternative to electricity exists for most appliances and for lighting.

Between 1997 and 2025, the efficiency-adjusted price of natural gas increases by 10 percent in Case 1 and by 23 percent in Case 2. Over the same period, the efficiency-adjusted price of LFO declines by 16 percent in Case 1 and 20 percent in Case 2. In both cases, there is an incentive to substitute LFO with gas, although this incentive becomes quite small late in the period in Case 2. Furnace efficiencies are assumed to improve over time, which contributes to the reduction in LFO prices and slows the increase in natural gas prices.

Residential Demand and Market Shares

Both cases project a steady increase in energy consumption in the residential sector. In Case 1, total consumption rises from 1 606 PJ in 1997 to 2 104 PJ in 2025, an annual growth rate of 1.0 percent (Figure 3.4). In Case 2, due to the greater adoption of efficient technologies, total energy demand increases more slowly, at an average rate of 0.5 percent, to reach 1 850 PJ in 2025. By 2025, there is a difference of about 14 percent between Case 1 and Case 2. Total energy demand for the A&R Sensitivity is virtually identical to Case 2, although more solar energy and wood are used.

Natural gas is the primary fuel used in Canada for space heating and is becoming more common for water heating. The predominant use of LFO is space heating. LFO use is becoming less common in new homes, but continues to be used in areas not serviced by natural gas. Electricity is used primarily for lighting, appliances and water heating, but it is also used for space heating, particularly in Québec.

Space heating is the largest end use for energy in the residential sector, but its relative share is expected to decline. Typically, newer homes require less energy as they are built with more insulation, better windows and often incorporate natural lighting which supplies passive solar heating. In addition, newer furnaces tend to be more energy efficient. This contributes to a market share reduction for fuels used primarily for space heating. Since home design and furnace improvements are expected to be greater in Case 2, the decline in the combined market share of natural gas and LFO is more pronounced in that case.

Natural gas represented about 43 percent of residential energy demand in 1997. In Case 1, the market share of gas increases slightly by 2005 but then declines to 43 percent in 2025. In Case 2, the market share of

Figure 3.3
Residential Efficiency-Adjusted Fuel Prices

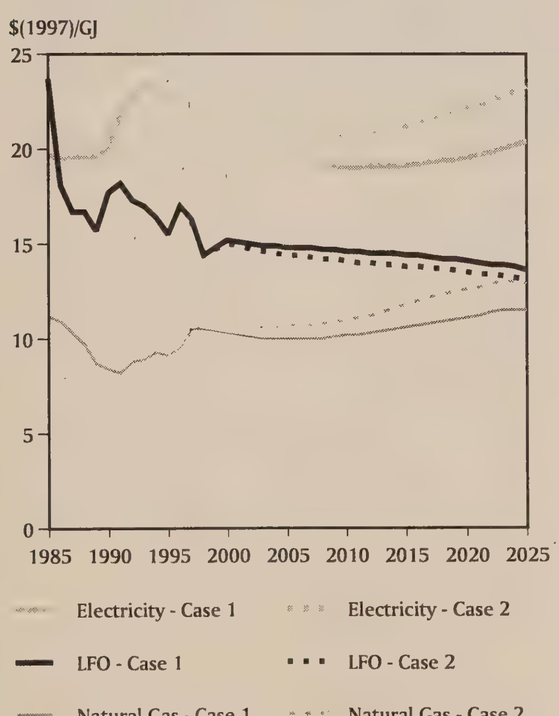
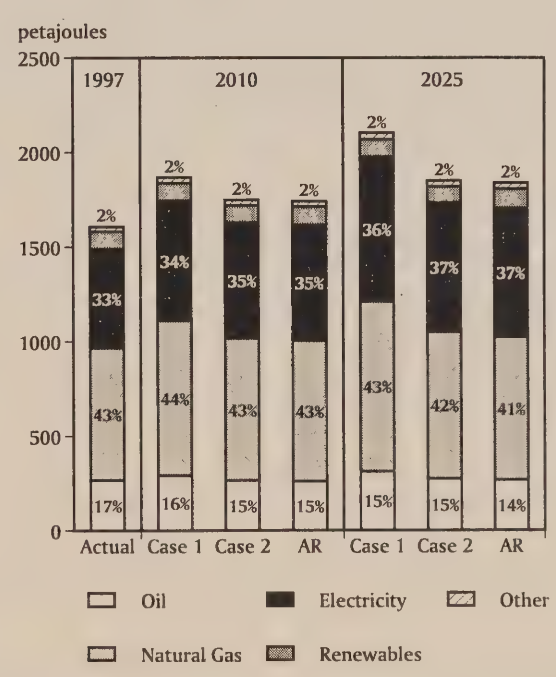


Figure 3.4
Residential Energy Demand by Fuel



natural gas is projected to fall throughout the period to reach 42 percent in 2025. In the A&R Sensitivity, it declines to 41 percent by 2025. In all cases, natural gas is expected to make inroads in Atlantic Canada.

Oil products, excluding diesel (DFO) used in farm equipment, represented 10 percent of residential demand in 1997. LFO accounted for most of this share, although some kerosene and heavy fuel oil were also used. In Case 1, the oil share is expected to decline gradually to 8 percent by 2025. In Case 2, it declines more rapidly to 8.5 percent by 2014 and then levels off. In the A&R Sensitivity, it declines to under 8 percent. In addition, the market share for farm DFO is relatively stable at 6.5 percent in all cases.

The market share of electricity is expected to grow due to increased penetration of small appliances and air conditioning in Canadian households. The penetration of small appliances such as home computers, microwaves, compact disc players and video cassette recorders has increased significantly over the past few years. This trend is assumed to continue into the projection period. Nevertheless, newer appliances are assumed to be more efficient, which somewhat mitigates the increase in the market share of electricity.

Electricity represented 33 percent of residential energy demand in 1997. In Case 1, the market share for electricity increases to roughly 36 percent by 2025. In Case 2 and the A&R Sensitivity, it increases to slightly over 37 percent. The greater increases in market share for electricity in Case 2 and the A&R Sensitivity result from to the larger declines in natural gas and LFO resulting from the improvements in efficiency of heating equipment.

Wood represented 5.6 percent of residential demand in 1997. By 2025, its market share decreases to 4.3 percent in Case 1 and 4.4 percent in Case 2. In the A&R Sensitivity, the number of wood-stove users increases, but more efficient wood and wood pellet stoves are assumed to penetrate the market. The resulting market share is similar to that of Case 2.

Solar energy was estimated at 0.1 percent of the residential market in 1997. In Case 1 and Case 2, its share is assumed to remain relatively constant. In the A&R Sensitivity, its market share increases to 1.2 percent due to inroads in the water and space heating markets.

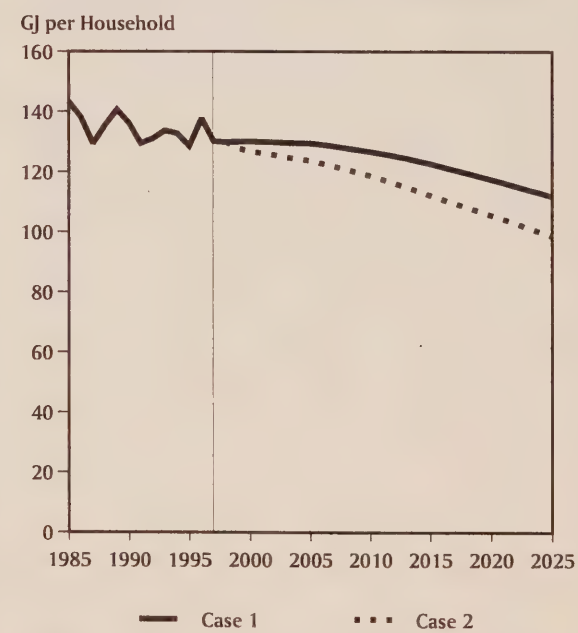
Together, propane, steam and coal accounted for 1.6 percent of demand in 1997. In all cases, their combined market share remains relatively constant throughout the projection period.

Residential Energy Intensity

Energy intensity is volatile because it is heavily influenced by weather patterns. During particularly cold years, the average energy use per household is higher, while warmer years correspond to lower energy use. The projected trends are smooth because the projections assume normal weather patterns.[3]

All cases project steadily decreasing energy use per household throughout the period (Figure 3.5). In Case 1, energy intensity, excluding agricultural use, is expected to decline at an annual rate of 0.5 percent. In Case 2 and the A&R Sensitivity, it declines by 1.0 percent per year. Several factors lead to these declines: more efficient houses, furnaces, appliances and lighting equipment. Also, energy-efficient technologies are introduced into the housing stock through new houses and retrofits.

Figure 3.5
Residential Energy Intensity
(excluding DFO used to power farm equipmment)



3 Normal weather patterns are defined as the average temperature between 1961 and 1990.

In all cases, energy efficiency improvements are slower between 1997 and 2010 than later in the period. This is partly explained by demographic changes which are expected to intensify after 2010. Smaller families and the ageing of the population will likely result in smaller homes (e.g., semi-detached, apartments or retirement communities), which require less energy.

3.3.2 Commercial Sector

The commercial sector is composed of offices, retail buildings, hospitals, schools, warehouses, restaurants, recreational facilities, hotels and motels. In 1997, the largest component of end use consumption was space heating (55 percent), followed by lighting (14 percent), motors (12 percent), water heating (7 percent), office equipment (7 percent) and cooling (5 percent). Motors are used to operate fans, compressors and pumps.

Energy consumption increases with economic growth but at a slower rate because new equipment and buildings tend to be more energy efficient than existing ones. Real commercial GDP is expected to grow at 2.3 percent in the early part of the projection period (1997 to 2010) but is expected to slow to 1.5 percent in the latter part. Other factors which determine energy demand in the commercial sector are energy prices, technological developments, consumer attitudes, and government and industry initiatives.

Commercial Efficiency-Adjusted Energy Prices

The most important fuels in the commercial sector are electricity, natural gas and LFO. Figure 3.6 shows the average Canadian efficiency-adjusted prices for these fuels for Case 1 and Case 2.

Consumers have more of an incentive to limit their energy consumption when energy is relatively more expensive, as it is in Case 2. Relative fuel prices also play a role in energy choices. Lighting and office equipment are exclusively powered by electricity so competition between electricity and fossil fuels is limited. Natural gas and LFO are commonly used for space heating. In Case 2, more efficient furnaces and boilers are assumed, which reduces efficiency-adjusted prices for LFO and natural gas.

In Case 1, the difference between the efficiency-adjusted prices of LFO and natural gas narrows, but gas keeps its advantage. In Case 2, a crossover occurs around 2016 and natural gas becomes relatively more expensive. It was assumed that a price differential exceeding 10 percent will trigger a shift towards LFO for space heating.

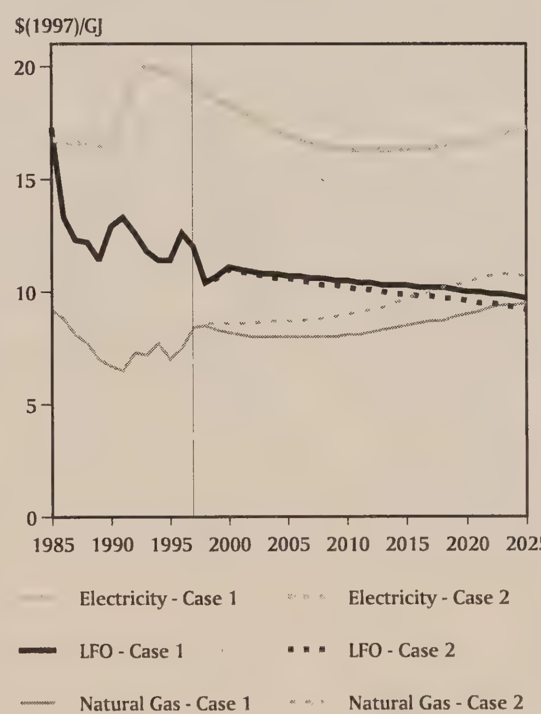
Commercial Energy Demand and Market Shares

Between 1985 and 1997, commercial demand grew by 1.5 percent per year to reach 984 PJ in 1997. In the projection period, growth in consumption is expected to average 1.3 percent per year in Case 1 and 0.9 percent in Case 2 (Figure 3.7). By 2025, demand reaches 1 398 PJ in Case 1 and 1 255 PJ in Case 2, a difference of 11 percent. The A&R Sensitivity assumes some penetration for solar energy, but is otherwise similar to Case 2.

The fuel mix presented in this section is a Canadian average. It should be noted that significant regional variations exist because of differences in relative prices, market structure and fuel availability. In all cases, market shares stay relatively constant over the projection period.

The market share of electricity grew from 37 percent in 1985 to 44 percent in 1997. Much of this increase can be attributed to the rapid penetration of office equipment. The share of electricity is projected to

Figure 3.6
Commercial Efficiency-Adjusted Fuel Prices



remain at its 1997 level in Case 1 and to increase slightly to 45 percent in Case 2. Factors contributing to this stabilization include saturation in the demand for office equipment; penetration of power-managed office equipment; and more stringent federal regulations for lighting products, three-phase electric motors, large air-conditioners and large heat pumps. It was assumed that more consumers purchase equipment that exceeds efficiency regulations in Case 2 than in Case 1.

New buildings are assumed to have more insulation, better windows and more efficient heating and cooling equipment. These features are expected to decrease space heating requirements. Nevertheless, the combined fuel share of LFO and natural gas is expected to stay fairly stable during the projection period.

In Case 1, LFO maintains its 1997 share of 5 percent and natural gas increases its share from 43 to 45 percent. The introduction of Scotian Shelf gas in the Atlantic region and the continued relative price advantage of gas over LFO explain the growth for gas. In Case 2, LFO becomes relatively cheaper than natural gas after 2016, and its market share rises from 5 to 6 percent by 2025. The market share for natural gas remains fairly constant. In addition, the share of other oil products (diesel, heavy fuel oil and kerosene) falls from 5 percent in 1997 to about 3 percent by 2025 in all cases.

Other fuels made up 4 percent of commercial energy use in 1997. These fuels include steam and propane. In all cases, their combined share falls to 3 percent by 2025. In the A&R Sensitivity, some solar energy is assumed to penetrate the water and space heating markets. Solar energy captures a market share of 0.1 percent by 2025.

Commercial Energy Intensity

Commercial energy intensity is measured by the energy use per dollar of real commercial GDP and is an indicator of energy efficiency. From 1985 to 1990, energy intensity declined by 2.1 percent per year (Figure 3.8). However, in the 1990 to 1997 period, the trend was reversed. High vacancy rates during the recession of the early 1990s may have contributed to rising intensities since buildings must be heated to a certain standard, even when unoccupied.

Energy intensity is expected to decline by 0.5 percent per year in Case 1 and 0.9 percent in Case 2.[4]

Figure 3.7
Commercial Energy Demand by Fuel

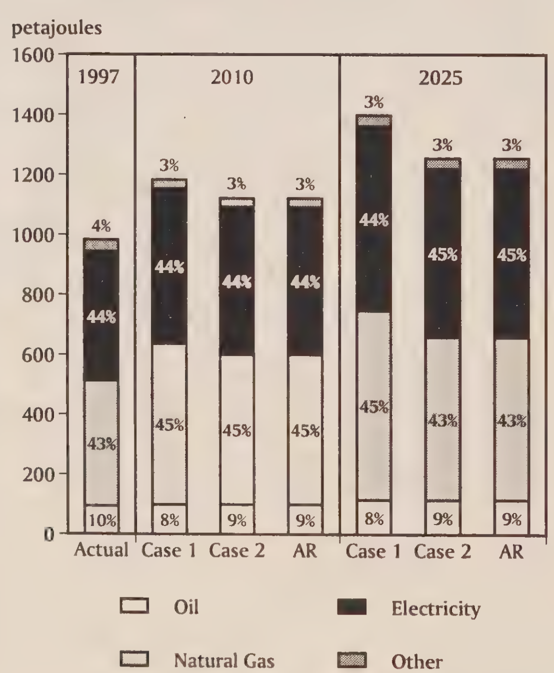
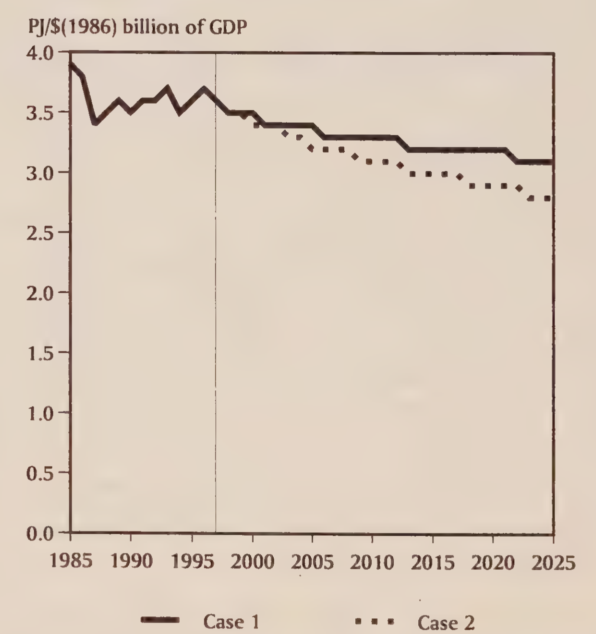


Figure 3.8
Commercial Energy Intensity



4 Because different types of commercial buildings have different energy needs, a change in the composition of the sector could alter intensity levels. However, such a structural shift is not expected to have a notable impact.

Falling vacancy rates will contribute to stronger effiency improvements in the near term. The decline will also be supported by new construction and retrofits and by various energy conservation measures. Such measures include the set-back of heating and lighting systems when buildings are unoccupied and regular servicing and maintenance of space conditioning equipment. These factors have a greater impact in Case 2 and the A&R Sensitivity than in Case 1.

3.3.3 Industrial Sector

The industrial sector includes manufacturing, mining, forestry and construction. Its most energy intensive industries are: pulp and paper, iron and steel, smelting and refining, chemicals, cement and petroleum refining. Although they account for less than 20 percent of industrial GDP, these six industries account for more than 60 percent of industrial energy demand. Therefore, the economic outlook for these industries has a significant impact on overall industrial energy demand.

Table 3.1 shows the average annual real GDP growth assumed for the industrial sector and various industries and groupings. These assumptions are the same in all cases. Total industrial GDP growth is expected to average 2.3 percent per year over the projection period. Growth is expected to be stronger in the earlier part of the projection; between 1997 and 2010, it averages 2.6 percent while it averages 2.1 percent between 2011 and 2025.

Table 3.1
Average Annual Real GDP Growth - 1997 to 2025

Industry	Growth Rate (percent)
Pulp and Paper	0.7
Iron and Steel	2.7
Smelting and Refining	2.9
Cement	0.9
Petroleum Refining	0.9
Chemicals	2.8
Energy-Intensive Industries	**2.1**
Other Manufacturing	2.8
Mining	1.5
Forestry	1.1
Construction	2.0
Less-Intensive Industries	**2.4**
Total Industrial Sector	**2.3**

With few exceptions, energy-intensive industries, especially those based on natural resources, are expected to grow at a slower pace than less-intensive industries. This is particularly notable later in the projection period. Between 1997 and 2010, energy intensive industries are projected to grow at 2.6 percent per year; after 2010, at 1.7 percent. This structural change will contribute to lowering the energy intensity of the industrial sector.

Industrial Efficiency-Adjusted Energy Prices

High energy prices encourage more efficient use of energy and lead to lower levels of demand. Alternatively, low energy prices may lead to increased demand by fostering growth in energy-intensive industries. Relative prices also influence energy consumption in the industrial sector where users often have the option of using different fuels. This is particularly true in the long term when new equipment may be purchased to allow substitution by a cheaper fuel.

The most widely used fuels in the industrial sector are natural gas, electricity and heavy fuel oil (HFO). Figure 3.9 presents the average Canadian efficiency-adjusted prices for these fuels. Prices for Case 2 and the A&R Sensitivity are identical. In all cases, fuel efficiencies for boilers are assumed constant.

The efficiency-adjusted price of HFO is relatively constant in both cases. The price of natural gas increases over the projection period in both cases; by 34 percent in Case 1 and by 67 percent in Case 2. In Case 1, the prices of HFO and natural gas remain close to each other, minimizing incentives for substitution. In Case 2, the price of natural gas diverges from the price of HFO around 2005. This leads to a shift away from gas and towards HFO in eastern Canada, where gas prices are higher than in western Canada.

Electricity tends to be used in processes where substitution by other fuels is limited or not feasible. This explains its importance as a fuel despite relatively higher prices than HFO or natural gas. By 2025, electricity prices are 14 percent higher in Case 2 than in Case 1. More so than for other fuels, there are substantial regional differences in the price of electricity. Prices are considerably lower than the Canadian average in the hydro-rich provinces of Manitoba, Québec and British

Columbia; they are notably higher in Ontario.

Industrial Demand and Market Shares

Total industrial energy demand was 2 921 PJ in 1997. In Case 1, it is expected to grow at an average of 1.7 percent per year to reach 4 720 PJ in 2025 (Figure 3.10). In Case 2, the average annual increase is expected to be 1.1 percent and energy consumption reaches 4 046 PJ in 2025. By 2025, there is a difference of about 17 percent between Case 1 and Case 2. Total demand in the A&R Sensitivity is similar to Case 2, although the A&R Sensitivity uses more hog fuel and some solar energy.

Natural gas accounted for 37 percent of industrial demand in 1997. In Case 1, the market share of gas increases to 43 percent by 2011, and then remains stable to the end of the projection. In Case 2, the market share of natural gas peaks at 41 percent in 2011, but then declines to 39 percent by 2025. In the A&R Sensitivity, the market share for gas is roughly one percent below that of Case 2. The strong growth in gas to 2011 is driven, in part, by investments in bitumen extraction facilities in Alberta which require large amounts of gas-generated steam. The introduction of natural gas in Nova Scotia and New Brunswick also contributes to increasing its market share.

The market share of electricity increases in all cases, from 26 percent in 1997 to roughly 29 percent in 2025. This is encouraged by robust increases in the use of electricity-specific processes in several industries. Such processes include mechanical pulping in the pulp and paper industry, electric arc furnaces in the steel industry and the use of robotics in various industries.

The combined use of oil products represented 10 percent of industrial demand in 1997. Of this amount, 43 percent was DFO, 35 percent HFO, 17 percent petroleum coke and 5 percent LFO. DFO is used to power heavy equipment, while the other oil products are used primarily in boilers to generate process heat. In Case 1, the market share of oil is expected to decline to 8 percent around 2010, then increases to 8.5 percent by 2025. The decline is caused by reduced shares of DFO and HFO. In Case 2 and the A&R Sensitivity, oil demand declines slightly before rising to 12 percent in 2025. The increase in oil demand is caused by an increase in HFO use in eastern Canada, where HFO becomes significantly cheaper than natural gas. The shares of DFO, LFO and

Figure 3.9
Industrial Efficiency-Adjusted Fuel Prices

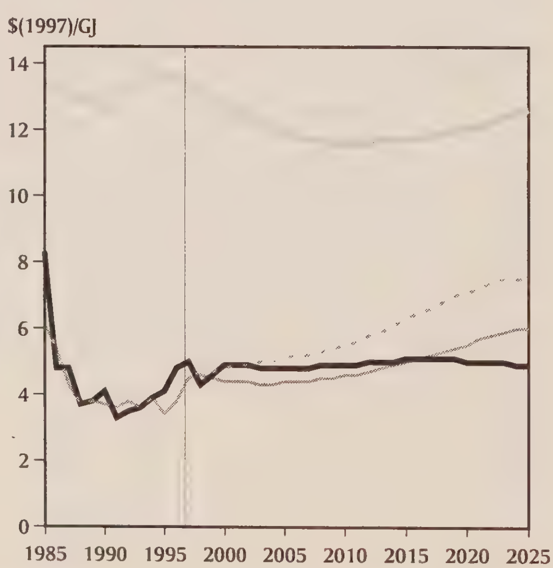
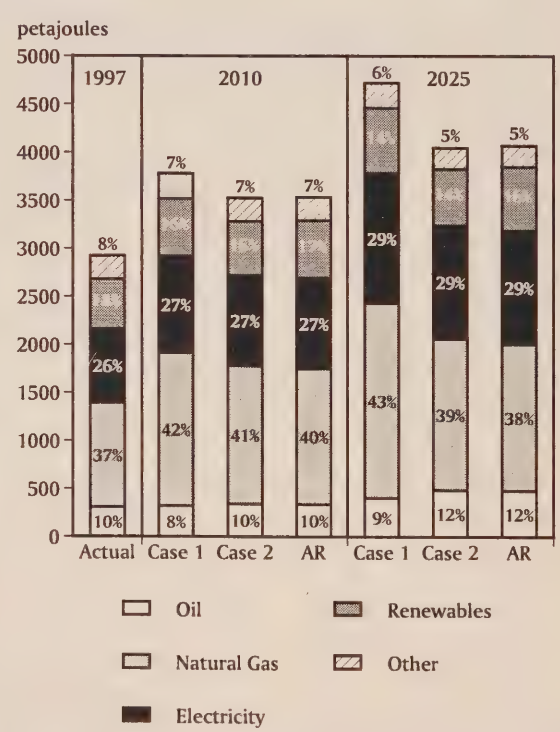


Figure 3.10
Industrial Energy Demand by Fuel



petroleum coke are similar in all cases.

Pulping liquor and hog fuel are by-products of the pulp and paper industry and are used almost exclusively in that industry. Together, they accounted for 18 percent of industrial demand in 1997. All cases assume a more widespread use of these fuels within the pulp and paper industry. However, due to the relatively slow growth expected in that industry, the combined share of hog fuel and pulping liquor is expected to decline to about 14 percent in Case 1 and Case 2, and to 16 percent in the A&R Sensitivity. Compared to Case 2, the consumption of hog fuel in the A&R Sensitivity is nearly 40 percent greater, reflecting the view that only a portion of avaiv-able supply is currently used to produce energy. However, the consumption of pulping liquor is the same since most of the available supply is used to produce energy.

Together, all other fuels supplied 8 percent of industrial demand in 1997. These fuels are: coal, coke and coke oven gas (6 percent); steam (1 percent); and liquefied petroleum gases (LPG - 1 percent). In all cases, the market share for coal, coke and coke oven gas is expected to gradually decline to 4 percent by 2025. The market shares of steam and LPG are expected to remain fairly constant in all cases. A measurable amount of solar energy is assumed in the A&R Sensitivity. Active solar air heating systems are assumed to be installed on enough manufacturing facilities to account for 0.1 percent of industrial demand by 2010.

Industrial Energy Intensity

In the industrial sector, energy intensity is measured as energy consumption per unit of industrial GDP. While it is a useful indicator of energy efficiency, caution must be used when performing comparisons. For example, a sharp decline in commodity prices will lead to a reduction in the GDP of many industries. With similar levels of production and energy consumption, the energy intensity of these industries will appear to have increased sharply. Comparison between two regions can also be misleading. A region with a large resource-based sector will have a higher energy intensity than one with a more diverse industrial base. This does not mean that the first region uses energy less efficiently than the second region; it simply reflects the relatively high energy requirement of resource-based industries.

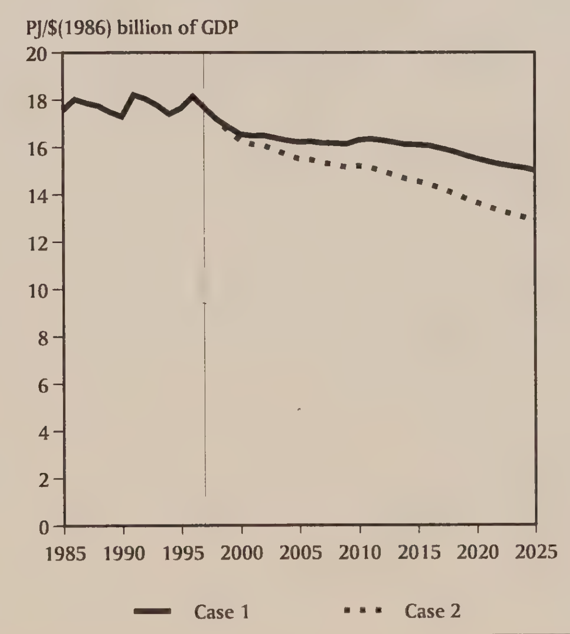
The average energy intensity for the Canadian industrial sector is expected to decline at an average of 0.6 percent per year in Case 1 and at an average of 1.1 percent per year in Case 2 (Figure 3.11). Energy intensity is similar in the A&R Sensitivity and Case 2.

Energy intensity is influenced by a variety of factors: structural changes, technological changes, and government and industry-sponsored energy conservation programs. Structural changes to Canada's industrial sector will lead to a reduction in energy intensity because energy intensive industries are expected to grow at a slower pace than less intensive industries.

Many programs provide incentives to industrial users to utilise energy more efficiently. The broadest-based program is the Canadian Industry Program for Energy Conservation (CIPEC). Under CIPEC, many industry sectors made voluntary commitments to achieving targets of energy intensity by the year 2000 (expressed either as energy per unit of GDP or energy per physical unit of production).

Different assumptions with respect to technological improvements account for most of the divergence in energy intensity between Case 1 and Case 2. Case 2 assumes greater adoption of new energy-saving technologies and of existing energy-efficient technologies.

Figure 3.11
Industrial Energy Intensity



INDUSTRY HIGHLIGHTS

An overview of the factors that were considered for key industries in developing the projections follows:

Pulp and Paper Industry

Slow GDP growth in the pulp and paper industry will act as an impediment to energy intensity improvements as it will discourage major investments in leading-edge equipment. Nevertheless, a greater reliance on recycled pulp will help reduce energy requirements. A more extensive use of mechanical pulping will also reduce energy needs but increase electricity utilization. However, the more intensive use of hog fuel and pulping liquor will somewhat increase energy intensity because these fuels have a lower fuel efficiency than fossil fuels. The net effect will be a modest reduction in energy intensity.

Iron and Steel Industry

Energy intensity in the iron and steel industry will continue to decrease due to a continued structural switch towards mini-mills which use electric arc furnaces that use scrap steel. Greater adoption of technologies such as pulverized coal injection and direct reduced iron will also reduce energy requirements, as they are more efficient than traditional processes.

Smelting and Refining

The smelting and refining industry is dominated by the aluminum industry, which relies almost exclusively on electricity. Energy requirements for newer facilities are significantly lower than for older ones. Improvements in intensity will occur mainly from investments in new plants and facility upgrades. While aluminum recycling would greatly reduce energy requirements, it is assumed that the Canadian industry will continue to focus on the production of aluminum from raw sources.

Cement

Cement production requires large amount of energy for heating and grinding. Typically, this energy can be produced from a wide range of fuels, including waste fuels such as paints, oils and solvents. Energy requirements are expected to decline somewhat through a greater use of heat recovery to dry raw material and for pre-heating. The conversion of the few remaining wet-process plants to the dry process would also reduce energy requirements.

Petroleum Refining

Energy intensity in the petroleum refining industry is expected to be stable. New investments are unlikely to be targeted at reducing energy requirements. It is expected that the industry will focus its investments towards other objectives, such as the production of low-sulphur gasoline.

Chemicals

The chemical industry is extremely diverse. It includes the production of industrial and agricultural chemicals, plastics, resins, fine chemicals and pharmaceuticals. Energy intensity will likely decline as a result of the projected stronger growth in the more value-added segment of the industry (i.e., fine chemicals and pharmaceuticals). New facilities are also expected to adopt more efficient technologies.

Mining

The mining industry includes metal, mineral and fossil fuel extraction. Fuel extraction, particularly bitumen, tends to be very energy intensive. Since the fuel segment of the industry is expected to grow more rapidly than the metal and mineral segments, energy intensity in the mining industry will increase slightly.

Other Manufacturing

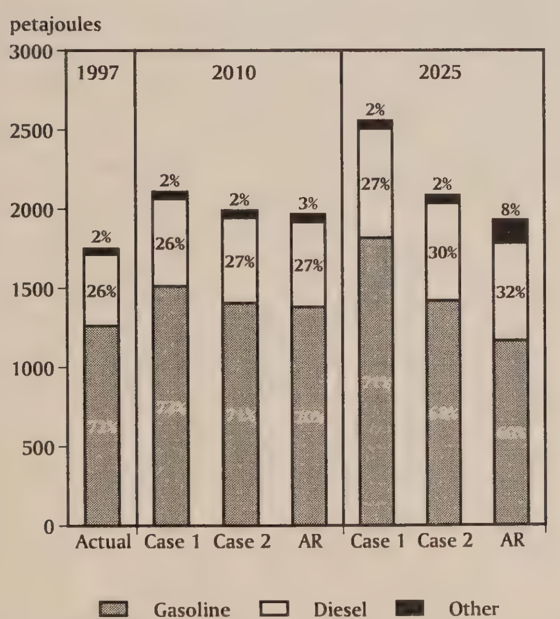
The other manufacturing grouping is very diverse and generally has low energy requirements relative to GDP. Since it represents a wide range of industries, numerous technologies will influence energy demand. The electrical and electronics products and the transportation equipment industries are expected to experience some of the most robust growth. Since the energy requirements of these two industries are typically lower than that of the overall grouping, energy intensity in this category is expected to decline.

3.3.4 Road Transportation

The transportation sector made up 25 percent of secondary energy demand in 1997. Road transportation consumed 82 percent of this energy, or 1 750 PJ. Motor gasoline,[5] which is mostly used by passenger vehicles,[6] accounted for 72 percent of demand; diesel, which is mostly used by freight trucks and buses, accounted for 26 percent. Together, propane, natural gas and electricity made up the remaining 2 percent. Electricity is used in subways and commuter trains; propane and natural gas are popular for fleet vehicles, such as taxis, delivery trucks and buses.

Between 1985 and 1997, total energy demand for road transportation grew by 1.8 percent per year. Over the projection period, annual energy growth is expected to average 1.4 percent per year in Case 1, 0.6 percent in Case 2 and 0.3 percent in the A&R Sensitivity (Figure 3.12). Energy demand reaches 2 555 PJ in Case 1, 2 082 PJ in Case 2 and 1 926 PJ in the A&R Sensitivity. The key difference between the three cases is the fuel economy of the stock. Faster and greater penetration of more fuel-efficient vehicles is assumed in Case 2 and the A&R Sensitivity than in Case 1.

Figure 3.12
Road Transportation Energy Demand by Fuel



In Case 1, fuel shares remain close to their 1997 levels. In Case 2, the share of gasoline falls to 68 percent while the share of diesel grows to 30 percent. In the A&R Sensitivity, gasoline declines to 61 percent and diesel increases to 32 percent. Methanol, which powers fuel cell vehicles in the A&R Sensitivity, makes up 5 percent of energy consumption by the end of the period. The combined share of propane, natural gas and electricity remains constant at about 2 percent in Case 1 and Case 2, while it rises to 3 percent in the A&R Sensitivity.

Passenger Vehicles

Between 1985 and 1997, energy demand for passenger vehicles increased by 1.6 percent per year. In 1997, demand reached 1 244 PJ; cars used about two-thirds of this energy. Demand is expected to grow at 1.5 percent per year in Case 1, 0.6 percent in Case 2 and 0.2 percent in the A&R Sensitivity. By 2025, it reaches 1 868 PJ in Case 1, 1 457 PJ in Case 2 and 1 301 PJ in the A&R Sensitivity.

The main factors affecting energy demand for passenger vehicles are the total stock of vehicles, the average fuel economy of the stock and the average number of kilometres travelled per vehicle (VKT). Projected growth rates for these factors are summarized in Table 3.2. In turn, these factors are influenced by demographics, income, prices and consumer preference.

Passenger Vehicles: Stock

Despite vehicle stock growth of 2.0 percent per year, the ratio of vehicles per household fell from 1.52 in 1990 to 1.46 in 1997. Declines in the average family

Table 3.2
Factors Affecting Passenger Vehicles Energy Demand
(average annual growth rate - percent)

	History 1985-1997	Case 1 1997-2025	Case 2 1997-2025	A&R Sensitivity 1997-2025
Energy Demand	1.6	1.5	0.6	0.2
Vehicle Stock	2.0	1.4	1.4	1.4
Fuel Economy - Stock	(1.7)	0.0	(0.9)	(1.3)
VKT	1.4	0.0	0.1	0.1

5 Motor gasoline used for agricultural vehicles is included in road transportation, but has been excluded from the breakdown into passenger and freight vehicles.

6 Passenger vehicles include cars and light trucks. Light trucks include pickup trucks, full-sized vans, minivans and sport utility vehicles.

size and an erosion of real household disposable income led to slower stock growth. In the projection period, the ratio of passenger vehicles per household is expected to further decline to 1.41 by 2015. In all cases, the stock of passenger vehicles grows at 1.4 percent per year.

Another trend in the 1990s has been the surge in the popularity of light trucks. In 1985, the split in vehicle sales between new cars and light trucks was 76/24; in 1997 it was 53/47. In the projection period the split is expected to stabilize at around 55/45.

New technologies such as hybrid electric vehicles (HEV) and fuel cell vehicles (FCV) are assumed to capture market share in all cases. In Case 1, HEV and FCV are introduced in 2010 and 2018 respectively and are projected to make up 10 and 5 percent of new car and truck sales by 2025. In Case 2, the introduction dates are the same but the rates of penetration are 20 percent for HEV and 10 percent for FCV. In the A&R Sensitivity, HEV are introduced in 2002 and FCV in 2006. By 2025, their shares of new sales are 30 and 20 percent respectively. In addition, FCV are assumed to be powered by methanol in the A&R Sensitivity while they are powered by gasoline in Case 1 and Case 2. Relative to the A&R Sensitivity, fairly conservative introduction dates for HEV and FCV were assumed for Case 1 and Case 2 because these technologies have yet to be commercially demonstrated and consumer acceptance is uncertain.

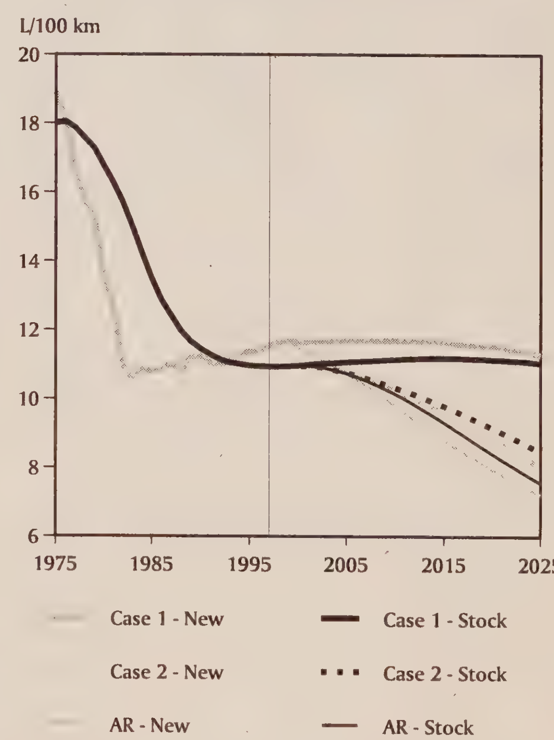
Passenger Vehicles: Fuel Economy[7]

In the late 1970s and early 1980s, escalating fuel prices and U.S. Corporate Average Fuel Economy (CAFE) standards encouraged producers to manufacture more fuel efficient vehicles. In this environment, the fuel economy of new vehicles was improved by almost 50 percent (Figure 3.13). Over the last decade, CAFE standards have remained unchanged and gasoline prices have fallen, thus weakening incentives for fuel economy improvements. In recent years, fuel economies for cars and for light trucks have stayed flat because the design changes which improve fuel economy have been offset by the increased penetration of features like air conditioning, interior space and engine power. However, the weighted average fuel economy of cars and light trucks has been trending upwards, due to the shift towards light trucks in the mix of passenger vehicles.

In Case 1, the fuel economy of new vehicles and of the stock are expected to converge and stabilize at about 11.0 L/100km. Before 2010, fuel economy improvements continue to be offset by amenities which include cell phones, computer plug-ins and navigational aids. After 2010, fuel economy is expected to improve following the introduction of HEV and FCV. These vehicles are assumed to be 25 and 33 percent more efficient than comparable internal combustion engine vehicles (ICEV).

In Case 2, new vehicle fuel economy is projected to improve by 1.3 percent per year. This translates into stock economy improvements in the range of 0.9 percent per year. By 2025, the average fuel economy of the stock is projected to be about 8.5 L/100km. In addition to the impact of HEV and FCV, fuel economy improvements are derived from increased use of light weight materials, reduced aerodynamic drag, better tires and improved engines and transmissions.

Figure 3.13
Fuel Economy - Passenger Vehicles[1]



1 The fuel economy of diesel ICEV and methanol FCV have been converted to gasoline equivalent to calculate the weighted average fuel economy of all passenger vehicles.

7 The average amount of fuel consumed by a vehicle to travel a certain distance (measured in L/100km)

In the A&R Sensitivity, the fuel economy of new vehicles is expected to improve by 1.7 percent per year, which leads to improvements of 1.3 percent per year in the fuel economy of the stock. Fuel economy assumptions for ICEV and HEV are the same as in Case 2. However, FCV use methanol instead of gasoline. Methanol-powered FCV are assumed to be 50 percent more efficient than comparable ICEV, while gasoline-powered FCV are 33 percent more efficient.

Passenger Vehicles: Average Number of Kilometres Travelled

Between 1985 and 1997, VKT increased by 1.4 percent per year. Factors contributing to VKT expansion included: longer commutes to the workplace, lower fuel prices and an increase in domestic road vacations. In the projection period, slower growth in domestic tourism and the ageing of the population are expected to moderate VKT growth. A study by the U.S. Department of Transportation[a] suggests that those aged 55 to 64 and those over 65 respectively drive 20 and 40 percent less than those aged 35 to 54. In 1997, 26 percent of Canadians were over 55 years of age; this share is expected to be 36 percent by 2016.

In Case 1, VKT grows at 0.3 percent per year between 1997 and 2010 and then declines by 0.2 percent per year for the rest of the projection period. Case 2 and the A&R Sensitivity reflect similar trends; VKT increases by 0.4 percent per year to 2010 and declines by 0.1 percent over the rest of the period. VKT is greater in Case 2 and the A&R Sensitivity because passenger vehicles are more fuel efficient which makes travel cheaper and encourages people to drive more.

Freight Trucks

There are two types of freight trucks: medium-heavy trucks (MHT), usually used for short haul; and extra-heavy trucks (XHT),[8] usually used for long haul. Since the 1970s, the trucking industry has been shifting from MHT to XHT, which resulted in increased use of diesel. Supported by strong growth in trucking GDP, energy demand grew by 2.5 percent per year between 1985 and 1997 to reach 461 PJ. Cross-border traffic has been the fastest growing component; in 1997, the trucking industry transported approximately 58 percent of Canada's exports to the U.S. and 80 percent of imports from the U.S.

In the study period, growth in trucking GDP is expected to moderate somewhat and energy demand is projected to grow at an average of 1.3 percent in Case 1 and 0.9 percent in Case 2. By 2025, energy demand for trucking reaches 655 PJ in Case 1 and 593 PJ in Case 2. The A&R Sensitivity is identical to Case 2.

The factors affecting energy demand in trucking are the stock of vehicles, the average fuel economy of the stock and the average number of kilometres travelled by each vehicle (Table 3.3).

Freight Trucks: Stock

The stock of XHT grew by 2.9 percent per year between 1985 and 1997 while the stock of MHT declined by 2.5 percent per year. In the study period, the stock of MHT is expected to stabilize and then experience growth in the range of 0.8 percent per year through 2025. The stock of XHT is expected to grow at 1.9 percent per year. In all cases, the internal combustion engine is expected to remain the dominant technology. Diesel engines are already very efficient; therefore, prospects for hybrid-electric and fuel cell engines are limited.

Freight Trucks: Fuel Economy

The fuel economy of the stock of MHT and XHT improved by 1.4 and 0.9 percent respectively between 1985 and 1997. In Case 1, the fuel economy of MHT and XHT are expected to improve by 0.5 and 0.4 percent per year respectively; in Case 2, by 0.7 and 0.8 percent. Figure 3.14 presents the weighted average fuel economy of MHT and XHT.

Table 3.3
Factors Affecting Freight Trucks Energy Demand
(average annual growth rate - percent)

	History 1985-1997	Case 1 1997-2025	Case 2 1997-2025
Energy Demand	2.5	1.3	0.9
MHT Stock	(2.5)	0.8	0.8
XHT Stock	2.9	1.9	1.9
Fuel Economy - MHT Stock	(1.4)	(0.5)	(0.7)
Fuel Economy - XHT Stock	(0.9)	(0.4)	(0.8)
Average Km Travelled	3.0	0.1	0.1
Trucking GDP	3.8	2.7	2.7

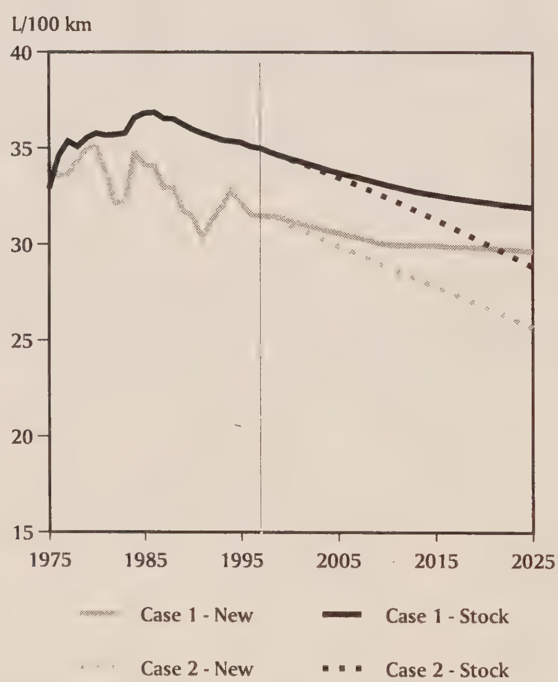
8 MHT weigh between 4 545 and 15 000 kilograms and consume gasoline or diesel; XHT weigh more than 15 000 kilograms and consume diesel.

In Case 1, fuel economy improvements for new trucks are restricted to established technologies such as better tires, better lubricants, and electronic engine and transmission controls. Most new vehicles are assumed to be equipped with these technologies by 2010. In Case 2, some advanced technologies are introduced after 2010. These advances, which are best suited to XHT, include ultra-high efficiency diesel engines, elimination of empty space and advanced drag reduction.

Freight Trucks: Average Number of Kilometres Travelled

In recent years, capacity utilization in the trucking industry has been very high. Between 1993 and 1997, average kilometres travelled for both types of trucks grew by 6 percent per year. In the projection period, growth in the stock of trucks, improved driver training, cooperation with bulk rail carriers and the use of computer systems (e.g., global positioning systems and two-way satellite communications links) are expected to improve productivity and flatten out the average number of kilometres travelled per truck.

Figure 3.14
Fuel Economy - Freight Trucks



1 The fuel economy of gasoline MHT has been converted to diesel equivalent to calculate the weighted average fuel economy of all freight trucks.

3.3.5 Other Transportation

Other transportation includes air, rail and marine. Together, they accounted for 18 percent of the energy consumed in the transportation sector in 1997, or 394 PJ. Of this amount, air represented 54 percent, rail 20 percent and marine 26 percent. The A&R Sensitivity is assumed to be identical to Case 2.

Air Transportation

Air transportation is mainly used for passenger travel. Aviation energy consumption is almost entirely in the form of aviation turbo fuel. Between 1985 and 1997, energy consumption increased by 2.6 percent per year to reach 214 PJ. Demand is influenced by changes in the demand for air transportation services (expressed in passenger-kilometres flown) and by efficiency improvements.

In Case 1, energy demand is projected to increase to 301 PJ by 2025, an average annual growth rate of 1.2 percent. In Case 2, energy demand increases to 290 PJ by 2025, an average annual growth rate of 1.1 percent. In both cases, energy demand grows at significantly slower rates than it did between 1985 and 1997. This is caused by a slower growth rate in passenger-kilometres traveled, which is influenced by two trends: a reduced growth rate in business travel made possible by improvements in telecommunication technologies; and an increase in recreational travel supported by the active lifestyles of Canada's ageing population. In both cases, replacement of older planes with newer and more efficient ones leads to improvements in energy efficiency. As a result, energy consumption per passenger-kilometre flown is projected to decline by 0.7 percent per year in Case 1 and by 0.8 percent per year in Case 2.

Rail Transportation

Railways are primarily used for bulk transportation of commodities destined for marine export. The energy consumption is made up entirely of DFO. Rail energy demand decreased from 85 PJ in 1985 to 80 PJ in 1997, an average decline of 0.3 percent per year. During this period, the demand for rail transportation services, as measured by Rail-GDP,[9] increased by 2.1 percent per year. This resulted in a reduction in energy intensity, as measured by energy demand per unit of GDP, of

9 Rail-GDP represents the total real GDP in mining, agriculture, manufacturing and forestry.

2.3 percent per year. The decline in energy intensity is mainly attributed to increased competition and restructuring which led to the use of higher capacity equipment and to increased average carload weight.

In Case 1, energy demand is projected to increase to 91 PJ by 2025, an average annual growth rate of 0.5 percent. In Case 2, energy demand is projected to reach 89 PJ by 2025, an average annual growth rate of 0.4 percent. Rail-GDP is projected to grow at 2.4 percent per year while energy intensity declines at an annual average rate of 1.8 percent in Case 1 and 1.9 percent in Case 2.

Marine Transportation

Marine transportation is mainly used to move bulk goods destined for export. Marine energy demand increased from 74 PJ in 1985 to 100 PJ in 1997, an annual rate of increase of 2.8 percent. HFO met 55 percent of this demand and DFO met 45 percent. In the same period, Marine-GDP[10] increased at an average of 2.1 percent per year. Energy intensity in the marine sector, as measured by marine energy demand per dollar of Marine-GDP, increased on average by 0.7 percent per year from 1985 to 1997.

In both cases, marine energy demand increases by 1.0 percent per year on average, to reach 132 PJ by 2025. Marine-GDP is projected to grow at 1.7 percent per year while the marine energy intensity declines at 0.7 percent per year. The slowing in the annual growth rate of energy demand reflects the projected slow GDP growth in mining, forestry and agriculture.

3.3.6 Non-Energy Use of Hydrocarbons

In addition to being used as energy sources, hydrocarbons are also employed in the production of non-energy products, such as petrochemicals, asphalt and lubricating agents. Non-energy hydrocarbon use in Canada totalled 826 PJ in 1997, nearly 10 percent of total secondary energy demand. Of this amount, 567 PJ was used as petrochemical feedstock, 127 PJ for making asphalt, and 132 PJ for the manufacturing of lubricants, greases and other petroleum products.

Petrochemical Feedstock

There are four major categories of feedstock used in the petrochemical industry: ethane, liquefied petroleum gases (LPG), oil and natural gas. While the industry as a whole uses various feedstock, most plants are only designed to handle one type. Ethane, LPG and oil can be used to produce various primary chemicals, such as olefins (ethylene, propylene and butylenes) and aromatics (benzene, toluene, xylenes). Alberta plants are primarily based on ethane, while those in eastern Canada are largely based on oil. LPG are also used as feedstock in Alberta, Ontario and Québec. Natural gas is used as a feedstock to produce methanol and ammonia in Alberta, British Columbia, Ontario and Manitoba.

The outlook for petrochemical feedstock is dependent on the world demand for primary chemicals and on the prices of natural gas and ethane. Due to the differences in the local supply and prices of these commodities, the projections for petrochemical feedstock vary between Case 1 and Case 2. The outlook for the various types of feedstock is summarized in Table 3.4.

The demand projections for ethane feedstock are directly linked to assumptions on new petrochemical plants and expansions as these plants tend to be large. Case 1 assumes the plant that has been expanded (1998) and that two new plants will be built (2000 and 2004) in Alberta. Case 2 assumes only one new plant (2004) and the same expansion for Alberta. In addition, both cases assume a new plant in Nova Scotia in 2001 and an expansion of that plant in 2011. In Case 1, ethane demand nearly triples and it more than doubles in Case 2. Due to the assumed retirement of older plants, ethane demand declines after 2018 in Case 1 and 2016 in Case 2.

Demand for other feedstock is often driven by plant expansions or capacity increases. As a result, specific

Table 3.4
Hydrocarbon Demand for Petrochemical Feedstock
(petajoules)

	1997	2010		2025	
		Case 1	Case 2	Case1	Case2
Ethane	120	348	300	304	256
LPG	67	94	94	118	118
Oil	160	189	189	239	239
Natural Gas	220	231	208	294	264
Total Feedstock	**567**	**862**	**791**	**955**	**877**

10 Marine-GDP represents total real GDP in mining, agriculture and forestry.

expansions and new plants have not been identified. In both cases, demand for oil is projected to grow by nearly 50 percent over the study period while the demand for LPG is expected to grow by 75 percent. In Case 1, demand for natural gas feedstock increases by 33 percent between 1997 and 2025, and by 20 percent in Case 2.

Other Non-Energy Use of Hydrocarbons

Asphalt is the single most significant application in this grouping. Production of asphalt is heavily influenced by investments on roads. Hydrocarbon demand for asphalt production increased at an average annual rate of 1.6 percent between 1984 and 1997. In both cases, it is projected to increase at an average annual rate of 0.7 percent to reach 154 PJ in 2025. The slower growth, compared to recent history, is the result of an increase in asphalt recycling and of modest anticipated increases in infrastructure investments.

Hydrocarbon demand for the manufacturing of lubricating oils and greases, petroleum coke and other non-energy uses is projected to grow at an average of 1.0 percent per year in both cases to reach 177 PJ in 2025.

3.4 SECONDARY ENERGY DEMAND BY REGION

Detailed data for each region is available in *Appendix 3: Demand*.

3.4.1 Atlantic Canada

Total energy demand was 560 PJ in 1997. In Case 1, it is expected to grow at an average of 0.9 percent per year to reach 723 PJ in 2025. In Case 2, the annual average increase is 0.5 percent and energy consumption reaches 651 PJ in 2025. By 2025, there is a difference of about 11 percent between Case 1 and Case 2. Currently, oil meets 61 percent of this demand, electricity 22 percent, renewable fuels 13 percent and other fuels 4 percent.

The exploitation of natural gas resources on the Scotian Shelf will have a significant impact on energy consumption patterns in the region. Natural gas will be introduced in Nova Scotia and New Brunswick in 2000. By the end of the projection period, natural gas accounts for 8 percent of end use energy demand in Atlantic Canada in Case 1 and 4 percent in Case 2. Most of this increase is at the expense of oil.

Propane is also expected to make inroads in the region. The local supply, which will be extracted from raw natural gas, is expected to be significantly cheaper than the present supply, which is shipped to the region by rail. In all cases, the market share of propane is projected to increase from 1.6 percent to approximately 2.5 percent.

The popularity of wood for space heating and the above-average presence of the pulp and paper industry, which relies heavily on hog fuel and pulping liquor as energy sources, contributes to the large proportion of renewable fuels consumed in the region.

Offshore oil production in Newfoundland is one of the key developments in the region. It will allow Newfoundland to exhibit more robust growth than other provinces in the early part of the projection. However, due to a lack of information on the amount of energy required by offshore projects, the energy demand associated with these projects has been excluded from the projections. Nevertheless, since most of the offshore needs are met by self-generated energy, this exclusion does not affect the balance between the supply and demand of energy.

3.4.2 Québec

Total energy demand in Québec was 1 709 PJ in 1997. In Case 1, it is projected to increase at an average of 1.3 percent per year to reach 2 462 PJ in 2025. In Case 2, it grows at an average of 0.8 percent per year to reach 2 146 PJ in 2025. The difference between Case 1 and Case 2 is approximately 15 percent by 2025. In 1997, electricity accounted for 36 percent of total energy demand, oil for 38 percent, natural gas for 14 percent, renewable fuels for 9 percent and other fuels for 3 percent. In all cases, these shares remain relatively stable over the projection period.

Québec has some of the lowest electricity prices in North America; as a result, electricity is a significant energy source. Large electricity users, such as the aluminum industry, are attracted to the province. In the residential sector, nearly 90 percent of new homes use electric space heating. In the commercial sector, electricity is less popular, accounting for 33 percent of space-heating requirements. Through the 1990s, natural gas has been making gains in the commercial space heating market at the expense of electricity. Since

natural gas is projected to lose its relative price advantage over LFO, this trend is expected to slow down in the projection period.

Light trucks are less popular in Québec than in the rest of Canada. In 1997 they accounted for 33 percent of new sales of passenger vehicles, whereas the Canadian average was 47 percent. Having more cars in the mix of passenger vehicles helps to curb average gasoline consumption per vehicle.

3.4.3 Ontario

In 1997, total energy demand was 2 726 PJ. In Case 1, it is projected to increase by 1.7 percent per year to reach 4 387 PJ in 2025. In Case 2, it is expected to grow at an average of 1.2 percent per year to reach 3 762 PJ. There is a difference of about 17 percent between Case 1 and Case 2 by 2025. Oil accounts for 38 percent of secondary energy demand, natural gas for 32 percent, electricity for 18 percent, renewable fuels for 4 percent and other fuels for 8 percent. These shares are similar to the Canadian average and are projected to be fairly stable during the projection period.

Industrial energy intensity is well below the Canadian average. This is partly due to above average electricity prices, which encourage efficient use of energy, and to a diverse industrial structure. In Ontario, the "other manufacturing" grouping accounts for more than two-thirds of industrial GDP. This grouping has relatively low energy requirements and energy uses are more in line with those of the commercial sector (i.e., space heating, lighting).

3.4.4 Manitoba

Total energy demand was 251 PJ in 1997. In Case 1, it is expected to grow at an average of 1.4 percent per year to reach 367 PJ in 2025. In Case 2, the annual average increase is 0.8 percent and demand peaks at 317 PJ in 2025. By 2025, there is a difference of about 16 percent between Case 1 and Case 2. In 1997, oil met 39 percent of energy demand, natural gas 31 percent, electricity 24 percent, renewable fuels 3 percent and other fuels 3 percent. These shares are projected to be fairly stable in the projection period.

Electricity prices are well below the Canadian average and electricity captures a slightly larger market share than the Canadian average. Through its Energy Efficient Lighting Program, Manitoba Hydro offers financial incentives to commercial and industrial customers who purchase the most efficient lighting system on the market (i.e., T8 bulbs paired with an electronic ballast) for retrofit or new construction projects.

3.4.5 Saskatchewan

In 1997, total energy demand was 374 PJ. In Case 1, demand grows at 1.1 percent per year to reach 507 PJ in 2025. In Case 2, it grows at an average of 0.6 percent per year to reach 440 PJ in 2025. There is a difference of about 15 percent between Case 1 and Case 2 by 2025. Natural gas makes up the largest portion of total energy consumption with a 40 percent market share. It is followed by oil at 39 percent, electricity at 16 percent, renewable fuels at 3 percent and other fuels at 2 percent. In all cases, these shares remain stable throughout the projection period.

The above average share of natural gas in Saskatchewan is primarily the result of industrial gas consumption. Natural gas accounts for 63 percent of energy consumed in the sector, compared to 34 percent in Canada. This is explained by relatively low prices of natural gas and by the significance of fossil fuel mining, which uses gas intensively.

The residential market accounts for a larger proportion of energy demand in the province than in the rest of Canada. This is the result of the proportionately large rural community in Saskatchewan; diesel used to power farm equipment is considered part of residential demand.

Light trucks have always been more popular in the prairies than in other provinces, which leads to above-average gasoline consumption per vehicle. In Saskatchewan, they account for 65 percent of new passenger vehicles sales, compared to 47 percent in all of Canada.

3.4.6 Alberta

Total energy demand was 1 729 PJ in 1997. In Case 1, it is expected to grow at an average of 1.5 percent per year to reach 2 607 PJ in 2025. In Case 2, it grows at 1.0 percent to reach 2 279 PJ in 2025. By 2025, there is a difference of about 14 percent between Case 1 and Case 2. Natural gas accounts for 46 percent of total energy demand. It is followed by oil

at 29 percent, electricity at 11 percent, other fuels at 11 percent and renewable fuels at 3 percent.

Several factors contribute to the high penetration of natural gas in the province. Natural gas is used more intensively in the residential and commercial sectors than in the rest of Canada. Also, the Board's projections assume strong growth in bitumen production and associated demand for gas-generated process heat. However, the GDP forecasts may not fully reflect the assumed expansion in bitumen production; hence, caution should be used in interpreting the energy intensity measure for Alberta.

The share of other fuels is expected to reach 14 percent by 2025, an increase of 3 percent. This high penetration comes from the significant presence of the petrochemical industry, which utilizes large quantities of ethane and LPG to manufacture primary chemicals. This industry is expected to exhibit substantial growth early in the projection period.

As in Saskatchewan, light trucks account for 65 percent of sales of new passenger vehicles, which results in above-average gasoline consumption per vehicle.

3.4.7 British Columbia and the Territories

Projections for British Columbia also include those for the Yukon, the Northwest Territories and Nunavut. The three territories account for about 3 percent of total energy consumption in the region.

Total energy demand for British Columbia and the Territories was 1 132 PJ in 1997. In Case 1, demand increases at an average of 1.1 percent per year to reach 1 535 PJ in 2025. In Case 2, growth averages 0.7 percent per year and demand peaks at 1 359 PJ in 2025. There is approximately a 13 percent difference between Case 1 and Case 2 by 2025. In 1997, oil met 36 percent of demand, natural gas 26 percent, electricity 18 percent, renewable fuels 18 percent and other fuels 2 percent. In Case 1 and Case 2, the market share of electricity is expected to increase from 18 to 20 percent.

The large penetration of renewable fuels is explained by the relative importance of the pulp and paper industry in British Columbia. That industry relies heavily on hog fuel and pulping liquor. However, the market share of renewable fuels is expected to decline from 18 to 16 percent, due to the slow projected growth of the pulp and paper industry.

Through the 1990s, natural gas has penetrated the residential and commercial space heating market at the expense of LFO. A worsening of the relative price of gas, a saturation of the urban market and a lack of gas service in more remote areas are expected to stabilize the market share of gas in the projection period.

3.5 PRIMARY ENERGY DEMAND

Primary energy demand represents the total energy requirement for Canada. It includes secondary demand, intermediate uses in transforming one energy form to another (e.g., coal to electricity) and energy used by suppliers in transporting energy to the market (e.g., pipeline fuel). Within this section, energy used to produce electricity for exports is excluded.[11]

Total primary demand was 11 061 PJ in 1997. On average, it is projected to grow by 1.4 percent per year in Case 1, 0.9 percent per year in Case 2 and 0.85 percent per year in the A&R Sensitivity (Table 3.5). Total primary demand is slightly lower in the A&R Sensitivity than in Case 2. This is due to the increased penetration of hydro, wind and solar energy, which have a theoretical fuel efficiency of 100 percent.

In all cases, natural gas overtakes oil products as the dominant primary fuel. Robust penetration in the

Table 3.5
Total Canadian Primary Energy Demand
(Petajoules)

	1997	Case 1 2025	Case 2 2025	A&R Sensitivity 2025
Oil	3 697	5 058	4 550	4 250
Natural Gas	3 385	6 030	4 937	4 905
Natural Gas Liquids	293	572	501	494
Coal	1 137	1 294	1 070	945
Hydro	983	1 374	1 238	1 241
Nuclear	938	1 132	1 132	1 132
Renewable Fuels	628	809	709	897
Total	11 061	16 268	14 138	13 865

11 Primary energy used to generate electricity is included in Chapter 4. The full balance between production, consumption, imports and exports of energy is presented in Chapter 9.

electricity generation market is responsible for most of this growth. The market share for natural gas climbs from 30 percent in 1997 to 37 percent by 2025 in Case 1, to over 35 percent in Case 2 and to 36 percent in the A&R Sensitivity. Some of the growth in the A&R Sensitivity is supported by the manufacturing of methanol for fuel cell vehicles.

In all cases, the share of natural gas liquids grows from 3 to 3.5 percent. The market share of oil declines from 33 percent in 1997 to 31 percent by 2025 in Case 1, 32 percent in Case 2 and 30 percent in the A&R Sensitivity.

Hydroelectric generation maintains its 9 percent share of total primary energy through the projection period. The share of nuclear energy declines from almost 9 percent in 1997 to about 7 percent by 2025 in Case 1, and 8 percent in both Case 2 and the A&R Sensitivity. The market share of coal falls from 10 percent in 1997 to 8 percent in Case 1, and 7 percent in both Case 2 and the A&R Sensitivity.

By 2025, the market share of renewable fuels is expected to decline from 6 percent in 1997 to 5 percent in Case 1 and Case 2. This is largely due to the expected slow growth in the pulp and paper industry, which currently accounts for more than 80 percent of renewable fuels consumption. The trend is reversed in the A&R Sensitivity, where renewable fuels increase their market share to 6.4 percent by 2025.

REFERENCES

a *National Personal Transportation Study 1995*, U.S. Department of Transportation, 1997.

CHAPTER 4

Electricity

4.1 INTRODUCTION

The analysis of electricity supply and associated primary energy requirements was performed for the two main cases described in Chapter 2: the Current Demand Trends/Low Cost Supply Case (Case 1) and the Accelerated Demand Efficiency/Current Supply Trends Case (Case 2).[1] Three sensitivity analyses were also conducted:

- The Transmission Sensitivity.
- The Alternative Technologies and Renewable Fuels Sensitivity.
- The Nuclear Generation Sensitivity.

4.2 ELECTRICITY RESTRUCTURING

Electricity restructuring in Canada is expected to impact on the electricity supply industry. Although the timing and magnitude of restructuring will vary from province to province, the basic trends include the unbundling of major utility functions into transmission, generation, distribution and marketing; allowing open access to transmission networks to facilitate electricity wheeling; competitive generation markets; and the development of power exchanges, power aggregators and brokers.

Electricity restructuring has gone furthest in the provinces of Alberta and Ontario. For example, Alberta was the first North American jurisdiction to implement a competitive framework in 1995, with customer choice expected to begin in 1999 and to prevail by 2001.

In 1999, Ontario Hydro was restructured into a holding company, an independent market operator, a generation company, and a transmission and distribution company. Ontario is expected to move to wholesale and retail competition in 2000. It is anticipated that, by 2010, Ontario Hydro will no longer be dominant in electricity generation.

Other restructuring initiatives have granted non-utility generators and neighbouring utilities transmission access. For example, British Columbia, Alberta, Manitoba and Québec have opened their transmission systems to competitors. As a result, they have gained wholesale marketing status in the U.S. Other jurisdictions are reviewing their policies and may follow.

In a restructured electricity environment, non-utility generators are expected to increase their share of generation. Distributed generation (DG) will also play a greater role. DG refers to small scale generation projects (generally less than 5 MW) implemented at, or close to, load centres; thus reducing transmission and distribution costs. Combustion turbines, internal combustion or new technologies such as fuel cells can apply to DG. It is assumed that DG will use natural gas in all cases.

4.3 METHODOLOGY

An in-house computer model, the Canadian Power Planning Program (CANPLAN), was used to perform the load/resource balance, to develop and analyse generation[2] planning , and to project energy trade. This was done on a provincial and territorial basis.

Key inputs to CANPLAN include projected electricity demand, current generating capacities and planned retirements and additions. Information provided by the utilities, stakeholders and public sources were considered. The model's main outputs relate to projected capacity, generation, interprovincial and international trade, and fuel requirements.

Power planning also takes into account peak demand, defined as the maximum load during a specific period of time (usually per hour or per day). Over the projection period, peak demand is projected to increase less rapidly than energy demand, reflecting the assumption of improving load factors over time, due to incen-

1 Detailed results are available in Appendix 4: Electricity.

2 Generation means the process of producing electric energy by transforming other forms of energy such as steam, heat or falling water. It also refers to the amount of electric energy produced.

tives for efficient use of energy such as time-of-use pricing.[3] For each province and territory, capacity expansion plans capable of reliably meeting system firm energy demand and peak load were developed.

A levelized unit energy cost analysis (LUEC) was performed for various types of new generation (Table 4.1). LUEC takes into account projected capital and operating costs of power plants. A real discount rate of 6 percent was assumed. The unit costs differ between Case 1 and Case 2 because of different fuel costs. With the exception of hydro generation, these costs are at the generating site.

Table 4.1
Levelized Unit Energy Costs
(1997¢/KW.h)

Province and Type	Case 1	Case 2
Newfoundland		
- Oil	4.54	4.54
- Hydro[1] (Labrador)	3.48	3.48
Nova Scotia		
- Combined-Cycle Gas	4.85	5.24
- Coal	5.04	5.41
New Brunswick		
- Nuclear	3.99	3.99
- Coal	4.26	4.49
- Combined-Cycle Gas	4.85	5.24
Québec		
- Hydro[1]	4.85	4.85
- Combined-Cycle Gas	5.73	6.23
Ontario		
- Nuclear	3.33	3.33
- Coal	3.54	3.79
- Combined-Cycle Gas	4.71	5.22
Manitoba		
- Hydro[1]	3.64	3.64
- Combined-Cycle Gas	4.88	5.38
Saskatchewan		
- Coal	3.12	3.24
- IGCC[2]	3.96	4.04
- Combined-Cycle Gas	3.98	4.50
Alberta		
- Coal	2.86	2.93
- Combined-Cycle Gas	3.57	3.61
- IGCC[2]	3.74	3.80
British Columbia		
- Hydro[1]	3.95	3.95
- Combined-Cycle Gas	3.78	4.28

1 Hydro generation includes the cost of transmission to market

2 Integrated Gasification Combined-Cycle

Hydro generation has the lowest unit energy costs in Labrador, Québec and Manitoba. It is also the least expensive option for British Columbia in Case 2. Coal will be the most economical option in Alberta and Saskatchewan and nuclear has the lowest cost in New Brunswick and Ontario. Gas is expected to provide the lowest cost for Nova Scotia and for British Columbia in Case 1. However, other factors, such as lead time, perceived business risk and preferences of power suppliers, often lead to the selection of a more expensive alternative in the projected generation choices. Therefore, the selection of generating systems was based on LUEC, the consultations, input from industry and judgement.

4.4 ELECTRICITY DEMAND, CAPACITY AND GENERATION

Total electricity demand in Canada is projected to grow at an average annual rate of 1.6 percent in Case 1 and at 1.2 percent in Case 2 between 1997 and 2025, reaching 820.6 TW.h and 728.1 TW.h respectively. These projections take into account the effects of the industry's own uses and system losses. Figure 4.1 presents an overview of projected electricity demand over the projection period.

To meet domestic demand and firm exports, total generating capacity is projected to increase from 108 GW in 1997 to 153 GW in Case 1 and to 134 GW in Case 2 (Figure 4.2). This represents a total increase of 42 and 24 percent respectively. Most of the capacity additions will be hydro-based or gas-fired.

Total domestic generation is expected to increase from 551.1 TW.h in 1997 to 838.2 TW.h in Case 1 and to 744.3 TW.h in Case 2, an average annual growth rate of 1.5 and 1.1 percent respectively (Figure 4.3). Generation takes into account interprovincial trade as well as imports and exports; thus projected growth rates may differ slightly from those related to domestic demand. Hydro generation is expected to remain predominant, but there will also be a shift towards more gas-fired

3 A rate design imposing higher charges during periods of the day when relatively higher peak demands are experienced.

generation. In both cases, the shares of nuclear and coal-fired generation are expected to decline.

4.5 ELECTRICITY DEMAND, CAPACITY AND GENERATION BY PROVINCE AND TERRITORY

4.5.1 Newfoundland and Labrador

Electricity demand in Newfoundland and Labrador is projected to increase from 11.4 TW.h in 1997 to 15.7 TW.h by 2025 in Case 1 and to 14.0 TW.h in Case 2. This translates to an average annual growth rate of 1.3 and 0.7 percent respectively. These projections exclude the potential load associated with the proposed Voisey Bay smelter project. Newfoundland Light & Power (NLP) serves about 85 percent of all retail customers on the island. Ten percent of the load served by NLP comes from its own small hydro generation capacity, and 90 percent from Newfoundland & Labrador Hydro. In 1997, the province accounted for 2.2 percent of total electricity demand and 8 percent of total generation in Canada.

Generating capacity is predominantly hydro-based and mainly concentrated in Labrador, which has one of the largest hydro generating facilities in Canada at Churchill Falls. Total capacity is projected to increase from 7 434 MW in 1997 to 11 173 MW in Case 1 and to 10 873 MW in Case 2 by 2025. In both cases, the overall increase reflects the announced Churchill Falls Phase 2 expansion and the Lower Churchill (Gull Island) development. Consequently, total hydro generating capacity is expected to increase to approximately

Figure 4.1
Electricity Demand

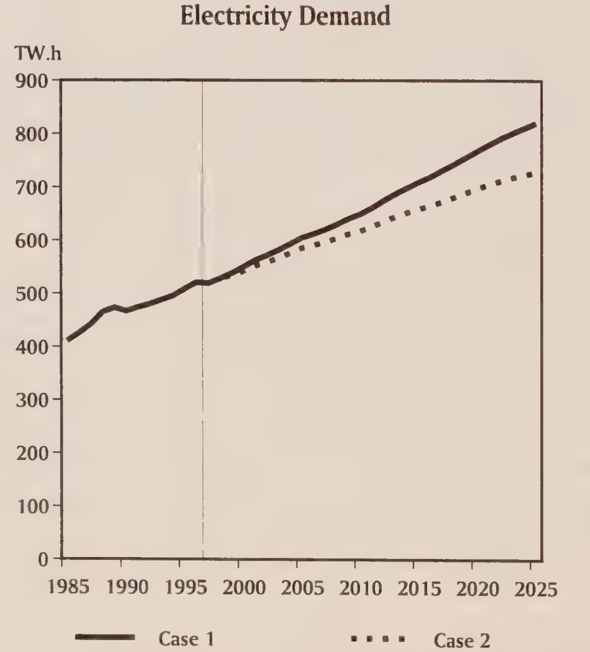


Figure 4.2
Generating Capacity by Fuel

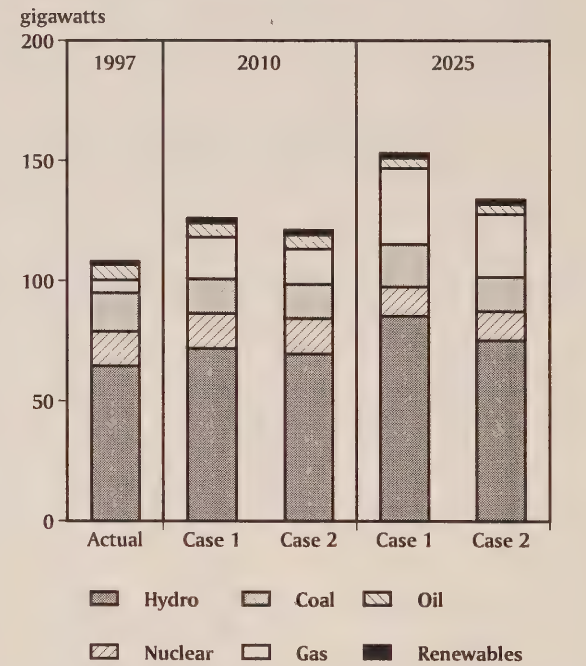
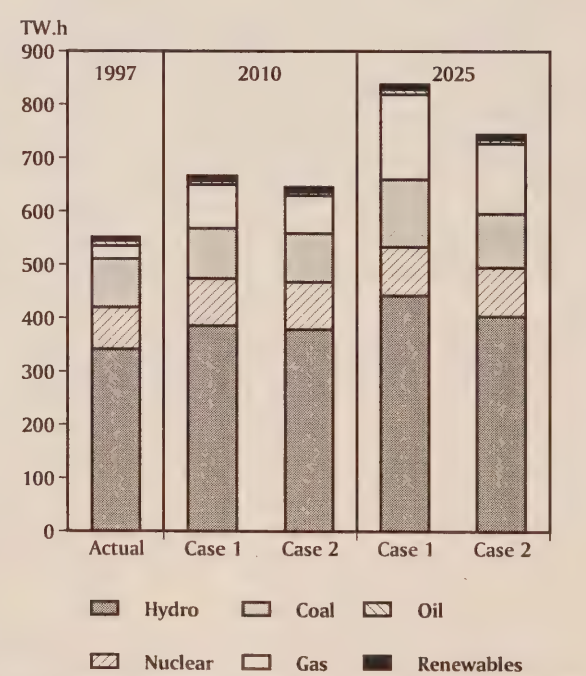


Figure 4.3
Generation by Fuel



10 000 MW by 2008. Oil-fired capacity, mostly installed on the island, is projected to increase from 825 MW to 1 177 MW in Case 1 and 877 MW in Case 2.

Total electricity generation in Newfoundland and Labrador is projected to rise from 41.7 TW.h in 1997 to 62.4 TW.h in Case 1 and 61.0 TW.h in Case 2 by 2025. The largest increases will occur in 2007-2008 due to the Churchill expansion and Gull Island development. Although a steady growth in oil-fired generation is expected to occur on the island due to demand growth, hydro's share of generation will remain over 91 percent throughout the period. Of the incremental energy generated by the Churchill projects, it was assumed that up to 17 TW.h will be purchased annually by Québec or wheeled through that province to other customers.

A key issue in the outlook relates to the choice of new generation in Newfoundland. The Granite Canal and Island Pond developments appear to be the last commercially viable sites on the island. Therefore, the choice for new generation will be between oil-fired generation and a high-voltage infeed from Labrador, although some gas-fired capacity could be built depending on natural gas transportation technology from offshore oil projects. In both cases, it was assumed that an infeed will not be built. This assumption is based on the view that, without the Voisey Bay smelter, incremental load requirements in Newfoundland will be small compared to the transmission capacity of an 800 MW line. During the consultations, it was suggested that an infeed could be justified as a replacement for more expensive and environmentally sensitive oil-fired generation on the island. Given the importance of this issue, an infeed has been included in the Transmission Sensitivity.

4.5.2 Prince Edward Island

Electricity demand in Prince Edward Island (PEI) is projected to increase from 0.89 TW.h in 1997 to 1.15 TW.h in Case 1 and to 1.07 TW.h in Case 2, an average annual growth rate of 0.9 and 0.5 percent respectively. PEI accounts for 0.2 percent of total electricity demand in Canada and relies mostly on New Brunswick for its electricity supply.

Total generating capacity, now exclusively oil-fired, is expected to increase from 107 MW in 1997 to 152 MW by 2025 in Case 1 and to 142 MW in Case 2. Maritime Electric Company Limited (MECL) currently operates two oil-fired power plants and has purchased 49 MW of capacity from New Brunswick Power's Point Lepreau nuclear plant and Dalhousie orimulsion generating station.

Total provincial generation is expected to rise from 0.02 TW.h in 1997 to 0.22 TW.h in 2025 in Case 1 and to 0.16 TW.h in Case 2. It was assumed that new generation will be exclusively oil-fired. Energy originating from New Brunswick is delivered via two marine cables installed during the 1970s with 400 MW of transmission capacity.

Over the study period, although local generation is projected to increase, PEI will continue to rely heavily on external sources to meet the provincial load requirements. This will likely require capacity increases to the interconnections with New Brunswick.

4.5.3 Nova Scotia

Electricity demand is projected to increase from 10.2 TW.h in 1997 to 13.2 TW.h in Case 1 and to 12.1 TW.h in Case 2. This translates to an average annual growth rate of 0.9 and 0.6 percent respectively. Nova Scotia accounts for about 2 percent of total Canadian electricity demand and generation.

Total generating capacity, which was 2 230 MW in 1997, is projected to increase marginally in Case 1 and to remain stable in Case 2. Gas-fired capacity will be installed by the year 2000 when the conversion of the Tufts Cove facilities will be completed. By 2025, gas-fired capcity will reach 1 373 MW in Case 1 and 1 256 MW in Case 2. The increase mainly reflects repowering[4] and replacements of retired coal and oil-fired plants. Coal and oil capacities are therefore projected to decline significantly while hydro capacity remains stable.

Electricity generation is projected to increase from 10.3 TW.h to 13.2 TW.h in Case 1 and to 12.1 TW.h in Case 2. A key factor affecting the outlook for Nova Scotia is the availability of Scotian Shelf natural gas, which emerges as an economically attractive option for new generation. The share of gas generation will rise to more than 60 percent in both cases. Coal genera-

4 Repowering generally increases the output of the plant and reduces its heat rate, thus improving overall efficiency.

tion, which now accounts for close to 80 percent of the total, is expected to decline significantly.

4.5.4 New Brunswick

Total electricity demand is expected to grow from 13.5 TW.h in 1997 to 18.8 TW.h by 2025 in Case 1 and to 17.3 TW.h in Case 2, which is an average annual growth rate of 1.2 and 0.9 percent respectively. New Brunswick accounts for 2.6 percent of total electricity demand and 3.0 percent of total generation in Canada.

Generating capacity will increase from 4 317 MW to 4 630 MW in Case 1, but will decline slightly in Case 2 because of lower demand and fewer plant replacements. In both cases, the Point-Lepreau nuclear plant, which accounts for about 15 percent of current provincial capacity, is assumed to be retired by 2023.

A key feature in this outlook is the emergence and sustained additions of new gas-fired facilities in the province. Over the projection period, the Board anticipates the installation of 2 801 MW of gas-fired capacity in Case 1 and 2 362 MW in Case 2. Due to the preference for gas, oil-fired capacity declines from 1 801 MW to 9 MW by 2025 in both cases.

Recently, NB Power and Tractebel announced plans to build a new 350 MW gas-fired plant at the existing Belledune station site. Commercial operation is expected to start by the end of 2001. In addition, NB Power and Westcoast Power are considering the conversion of a 100 MW oil-fired unit at Courtenay Bay into a 280 MW gas-fired combined-cycle plant by mid-2000. These plans were included in the projections.

Electricity generation is expected to rise from 16.7 TW.h to 23.1 TW.h and 21.5 TW.h for Case 1 and Case 2 respectively. These projections take into account PEI's load requirements. New Brunswick's generation is diversified, with coal accounting for 35 percent of the total, followed by oil (25 percent), nuclear (21 percent) and hydro (15 percent). The share of gas is expected to rise at the expense of coal and oil. By 2025, it is projected to reach 69 percent in Case 1 and 64 percent in Case 2.

4.5.5 Québec

Total electricity demand in Québec is projected to increase from 182.4 TW.h in 1997 to 266.8 TW.h in Case 1 and to 235.8 TW.h in Case 2, which is an average annual growth rate of 1.4 and 0.9 percent respectively. Québec accounts for 35 percent of total electricity demand and nearly 30 percent of total generation in Canada.

Total capacity is projected to rise from 33 895 MW to 47 227 MW in Case 1 and to 39 378 MW in Case 2. This represents total increases of 39 percent and 16 percent respectively. In Case 1, a project the size of the Great Whale project (3 200 MW) will be required by 2015. In Case 2, because of lower demand, only a portion of this capacity will be needed by 2023. Hydro capacity is projected to increase by 40 and 15 percent in Case 1 and Case 2, respectively. In both cases, it was assumed that the Gentilly 2 nuclear power plant will be retired by 2023.

Gas-fired capacity, associated mainly with distributed generation and cogeneration projects, is projected to increase from 454 MW in 1997 to 1 076 MW in Case 1 and to 1 161 MW in Case 2. Included in the projections is a wind energy program, whereby Hydro-Québec is expected to increase its purchases of wind energy which could total 450 MW by 2009.

Total provincial generation will rise from 166.1 TW.h in 1997 to 238.3 TW.h by 2025 in Case 1 and to 202.2 TW.h in Case 2. This translates into an average annual growth rate of 1.3 percent and 0.7 percent respectively. Notwithstanding the projected steady increase in gas-fired distributed generation, hydro generation in Québec will remain predominant, accounting for over 96 percent of the total by the end of the period. The projections take into account the increased flows from Labrador due to the Churchill expansion and Gull Island development.

4.5.6 Ontario

Total electricity demand in Ontario is expected to increase from 146.6 TW.h in 1997 to 268.4 TW.h by 2025 in Case 1 and to 235.1 TW.h in Case 2, an average annual growth rate of 2.2 percent and 1.7 percent respectively. Ontario accounts for nearly 28 percent of total Canadian electricity demand and 26 percent of total Canadian electricity generation.

The outlook for electricity supply in Ontario was developed on the basis of the following key assumptions: the currently non-operational nuclear units will be brought back to service by 2009; the newer nuclear

power plants (Pickering B, Bruce and Darlington) will be extended for five years beyond their 40-year design life and the older nuclear units (Pickering A) will be replaced by coal-fired units. This outlook assumes no construction of new nuclear power plants in Ontario.

Generating capacity is expected to increase from 30 314 MW in 1997 to 44 951 MW in 2025 in Case 1 and to 39 911 MW in Case 2. This represents a total increase of 48 and 32 percent respectively. In both cases, gas-fired capacity will experience significant growth, increasing from 1 661 MW in 1997 to 14 689 MW in 2025 in Case 1 and to 11 857 MW in Case 2.

Total provincial electricity generation is projected to expand at an average annual growth rate of 2.1 percent in Case 1 and of 1.7 percent in Case 2, reaching 263.2 TW.h and 231.0 TW.h respectively. A significant shift towards gas generation is anticipated in both cases; from 9.7 TW.h in 1997 to 67.8 TW.h in Case 1 and to 51.9 TW.h in Case 2. In Case 1, nuclear generation accounts for 35 percent of total generation by 2025, followed by gas (26 percent), coal (21 percent) and hydro (17 percent). In Case 2, nuclear generation is expected to account for about 40 percent of total generation by 2025, followed by gas (23 percent), hydro (19 percent) and coal (17 percent).

In both cases, the projections suggest that Ontario will become by far the largest market for gas-fired electric generation in Canada. Fossil fuel generation will exceed nuclear generation by 2020, despite the assumption of full recovery of existing nuclear plants. Given the uncertainty related to nuclear generation, the impacts of early nuclear retirements are examined in the Nuclear Generation Sensitivity.

4.5.7 Manitoba

Total electricity demand in Manitoba is projected to increase from 20.7 TW.h in 1997 to 30.2 TW.h in 2025 in Case 1 and to 27.2 TW.h in Case 2. This translates to an average annual growth rate of 1.4 percent and 1.0 percent respectively over the projection period. In 1997, the province accounted for nearly 4 percent of Canadian electricity demand and 6 percent of total generation.

Generating capacity is expected to rise from 5 132 MW in 1997 to 6 509 MW in 2025 in Case 1 and to 6 086 MW in Case 2, which represents a total increase of 27 and 19 percent respectively. Hydro capacity, which was 4 853 MW in 1997, is predominant and is expected to increase by 15 percent in both cases. It was assumed that Manitoba's coal power plants will be replaced by gas when they retire. Gas-fired capacity is expected to increase from 4 MW in 1997 to 873 MW in Case 1 and to 450 MW in Case 2. The larger increase in Case 1 reflects higher demand as well as higher levels of distributed generation. It is estimated that 800 MW of new gas capacity will be added between 2008 and 2022 in Case 1. In Case 2, gas capacity additions will not be required before 2014.

Total electricity generation in Manitoba is projected to increase from 33.6 TW.h in 1997 to 35.9 TW.h in Case 1 and to 35.2 TW.h in Case 2. This represents an average annual rate of 0.2 and 0.1 percent over the study period. Hydroelectricity, which currently accounts for 99 percent of total generation, will remain predominant. However, increases in gas generation will lead to a slight decline in the share of hydro. By 2025, gas-fired generation will account for 4.5 percent of the total in Case 1 and 2.5 percent in Case 2.

4.5.8 Saskatchewan

Total electricity demand in Saskatchewan is projected to rise from 17.7 TW.h in 1997 to 27.5 TW.h in 2025 in Case 1 and to 24.5 TW.h in Case 2. This represents an average annual growth rate of 1.6 and 1.2 percent respectively. The province accounts for nearly 3 percent of Canadian electricity demand and generation.

In 1997, total generating capacity in Saskatchewan was 2 935 MW, composed mainly of coal-fired (56 percent) and hydro (29 percent) stations. Hydro generating capacity is expected to remain stable in both cases at 870 MW. Coal-fired capacity is projected to increase from 1 635 MW in 1997 to 1 911 MW in Case 1, but no addition is required in Case 2. Gas-fired capacity is projected to increase from 394 MW in 1997 to 1 613 MW in Case 1 and 1 402 MW in Case 2 by 2025. Oil-fired capacity will remain constant at 31 MW in both cases.

In both cases, 210 MW of cogeneration capacity are assumed to be installed at the TransAlta/Husky plant at Lloydminster. The projections also assume the repowering of the Queen Elizabeth facilities.

Total provincial generation is projected to rise from 16.8 TW.h in 1997 to 27.0 TW.h in 2025 in Case 1 and to 24.0 TW.h in Case 2. The corresponding average annual growth rates are 1.7 percent and 1.3 percent respectively. In both cases, the increase is largely provided by gas-fired generation which is expected to rise from 0.9 TW.h in 1997 to 8.2 TW.h in Case 1 and to 7.3 TW.h in Case 2. Coal-fired generation is expected to increase from 11.7 TW.h in 1997 to 14.3 TW.h in Case 1 and to 12.3 TW.h in Case 2 by 2025. Hydro generation is projected to remain stable at about 4 TW.h in both cases.

There is more coal-fired capacity and generation projected in the results presented in the final report than in those presented in the Round 2 Consultations. During these consultations, some felt that some coal expansion would occur given the continued low cost of coal generation in Saskatchewan. Nevertheless, the market share of coal declines over the projection period, to the benefit of gas.

4.5.9 Alberta

Total electricity demand in Alberta is projected to increase at an average annual rate of 1.7 percent in Case 1 and 1.3 percent in Case 2, rising from 55.2 TW.h in 1997 to 88.0 TW.h and 78.7 TW.h respectively. In 1997, Alberta accounted for 10.6 percent of Canadian electricity demand and 10.0 percent of total generation.

In 1997, generating capacity was 8 252 MW (coal: 5 704 MW, gas: 1 518 MW, hydro: 841 MW, oil: 30 MW and renewable fuels: 159 MW). Capacity is expected to reach 13 392 MW in 2025 in Case 1 and 12 011 MW in Case 2, a total increase of 62 and 46 percent respectively. In Case 1, about 80 percent of the increase in capacity will be gas-fired and 20 percent, coal-fired. In Case 2, nearly all of the capacity additions will be gas-fired. Hydro and oil-fired capacity are expected to remain constant in both cases. Wind and biomass show a modest increase over the study period.

These capacity projections assume the repowering of the Rossdale, Clover Bar and Medicine Hat coal-fired plants, the commissioning of cogeneration facilities at Primrose (80 MW), Fort Saskatchewan (120 MW) and Joffre (400 MW), and the planned projects of TransAlta/Imperial Oil (220 MW) and TransAlta/Suncor (360 MW).

Total provincial generation is expected to increase from 54.0 TW.h in 1997 to 88.0 TW.h in 2025 in Case 1 and to 78.7 TW.h in Case 2. This translates into an average annual growth rate of 1.8 and 1.3 percent respectively. In Case 1, gas-fired generation is expected to quadruple over the projection period. The increase is slightly lower in Case 2. Consequently, the share of gas will rise to over 40 percent in both cases. Coal-fired generation is expected to remain the primary source for base load energy in Alberta. For similar reasons as in Saskatchewan, the final projections contain more coal than those presented in the Round 2 Consultations.

4.5.10 British Columbia

Total electricity demand in British Columbia is projected to rise from 60.9 TW.h in 1997 to 89.2 TW.h by 2025 in Case 1 and to 80.8 TW.h in Case 2, an average annual growth rate of 1.4 and 1.0 percent respectively. In 1997, British Columbia accounted for 12 percent of Canadian electricity demand and generation.

In 1997, total capacity in the province stood at 12 982 MW, of which nearly 85 percent was hydro-based. Gas generating capacity accounted for 10 percent, and oil and biomass together, for about 5 percent. Over the study period, total capacity is expected to increase to 17 818 MW in Case 1 and to 14 579 MW in Case 2. As for other provinces, it was assumed that surplus capacity will be used before any new capacity is built. As a result, hydro capacity increases in the 2014 to 2022 period in Case 1 but remains constant in Case 2. It was also assumed that a 150 MW coal power plant will be brought on stream in 2003. Due to the installation of distributed generation facilities, gas-fired capacity is expected to triple in Case 1 and to double in Case 2.

Total generation is projected to rise from 65.1 TW.h in 1997 to 85.3 TW.h in 2025 in Case 1 and to 76.9 TW.h in Case 2, an average annual growth rate of 1.0 percent and 0.6 percent respectively. Gas-fired generation will be the major contributor to this growth, rising from 3.8 TW.h in 1997 to 17.2 TW.h in Case 1 and to 10.7 TW.h in Case 2. Hydro generation will rise in absolute terms but its share of total generation will trend downward; from 90 percent in 1997 to 75 percent in Case 1 and to 81 percent in Case 2. The share of gas generation will rise to 20 and 14 percent in Case 1 and Case 2, respectively.

These generation projections take into account the Columbia River Treaty which provides that some of the power generated at hydro-electric plants on the U.S. portion of the Columbia River be returned to the Province of British Columbia. This treaty is being amended and it is assumed that B.C would resell its entitlements of power in U.S. markets after its domestic demand is met.

4.5.11 Yukon

Electrical energy demand in the Yukon was 0.37 TW.h in 1997. It is expected to increase to 0.54 TW.h in Case 1 and to 0.49 TW.h in Case 2. This represents an average annual growth rate of 1.4 percent and 1.0 percent respectively.

Generating capacity is projected to increase from 128 MW in 1997 to 157 MW in Case 1 and to 145 MW in Case 2. Over the study period, hydro generation is expected to increase marginally, reflecting small hydro development, but oil-fired generation is expected to capture most of the incremental demand.

4.5.12 Northwest Territories and Nunavut

Total electrical energy demand in the Northwest Territories and Nunavut is projected to grow at an average annual rate of 1.4 percent in Case 1 and 1.0 percent in Case 2, from 0.74 TW.h in 1997 to reach 1.09 TW.h and 0.99 TW.h by 2025 respectively.

Total generating capacity in 1997 was 242 MW of which nearly 70 percent was oil-fired. Given the current capacity surplus, no increase is expected in Case 2 and only some additional capacity will be required in Case 1 (249 MW) toward the end of the projection period. Most of the incremental demand will be met by oil-fired generation, although some repowering to gas generation is expected.

4.6 INTERPROVINCIAL AND INTERNATIONAL TRADE

Electricity trade can be divided into firm and interruptible trade. Firm trade tends to be long-term in nature, generally five years or more, and may involve the development of new generation or transmission facilities. Therefore, it may affect the expansion programs of generators. Interruptible trade is primarily used to optimize the relatively short-term operations of interconnected systems, and does not involve major expansion of facilities.

Trade projections are based on actual long-term contract data, information provided by the utilities, historical trade levels and projected surpluses.

4.6.1 Transmission Capacity

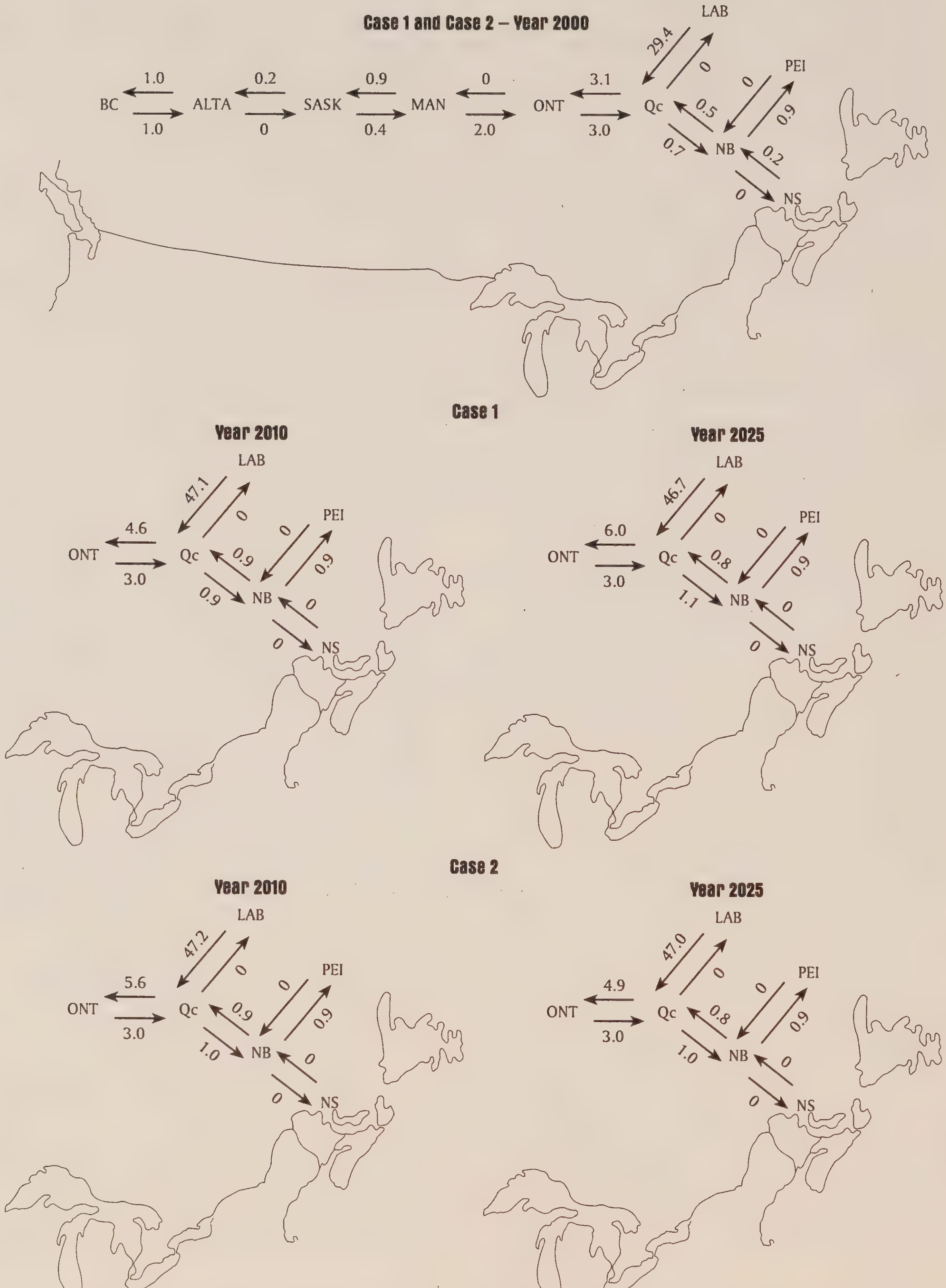
The transmission network conducts power from generating facilities to points of distribution. In Canada, it extends over approximately 158 000 kilometres and comprises 37 major interconnections with a total interprovincial transfer capability of 10 245 MW. With the exception of announced projects and the new transmission associated with the Churchill Falls expansion and Gull Island development, interprovincial and international transfer capacity were kept constant in both cases. This assumption was relaxed in the Transmission Sensitivity.

4.6.2 Interprovincial Trade

In 1997, interprovincial trade in Canada amounted to 43.2 TW.h. The direction of flows is generally dictated by the price differentials between adjacent provinces. Typically, interprovincial trade originates from hydro-based, low cost, provinces. Flows are generally larger in eastern Canada than in western Canada; those from Labrador to Québec account for about 70 percent of the total. Ontario has traditionally purchased some electricity from Québec and Manitoba. In the last two years, Alberta's electricity purchases from British Columbia have increased substantially due to rapidly rising demand. However, it was assumed that trade between these two provinces would go back to historical levels.

In Case 1, electricity flows from Labrador to Québec are expected to increase sharply when the Lower Churchill expansion project is completed. These peak at 47.2 TW.h in 2008 (Figure 4.4). Energy trade between Québec and New Brunswick is expected to be maintained around current levels. Net annual deliveries to Ontario from Québec and Manitoba are expected to increase beyond the 1997 levels, reaching 3.0 TW.h and 2.0 TW.h respectively by 2025. Higher energy exchanges between Québec and Ontario were assumed to allow generators to optimize their operations.

Figure 4.4
Interprovincial Trade
(TW.h)



Electricity flows between Alberta and British Columbia are expected to average 1.0 TW.h in both directions.

In Case 2, similar patterns of interprovincial trade are expected. In both cases, trade west of Ontario is expected to remain close to the 1997 level throughout the projection period.

In general, interprovincial trade is small, compared to electricity production, except for transfers from NB to PEI, and from Labrador to Québec.

4.6.3 International Trade

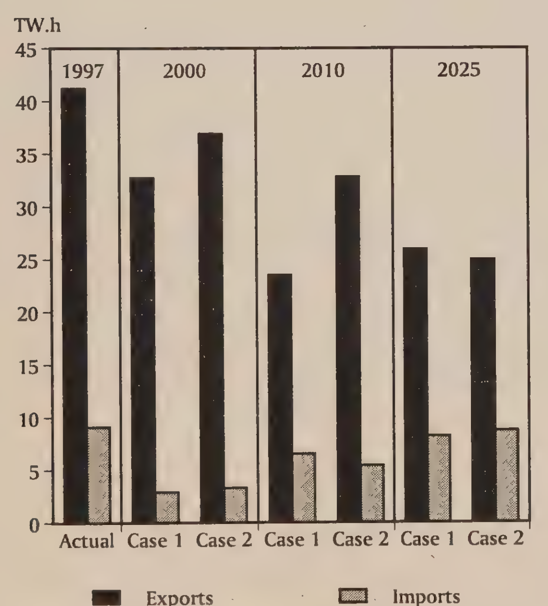
Canada is traditionally a net exporter of electricity. In 1997, total exports amounted to 41.2 TW.h, of which 95 percent were accounted for by Manitoba Hydro, Hydro Québec, B.C. Hydro, Ontario Hydro and New Brunswick Power, or their affiliated companies. Most of the exports are provided from hydroelectricity. The largest export markets are the New England States and Minnesota. In 1997, imports were 9.1 TW.h, of which 90 percent were destined to B.C. and Ontario.

In Case 1, total electricity exports are projected to fluctuate in the range of 20 to 30 TW.h, or between 3 and 6 percent of total generation (Figure 4.5). Exports will increase noticeably after 2008 due to the projected expansion in Labrador. As demand grows and energy surpluses diminish, exports will tend to decline thereafter. Québec, British Columbia, Manitoba, New Brunswick and Ontario are expected to continue to account for most Canadian electricity exports. Total imports are assumed to fluctuate around historical levels.

In Case 2, similar trends in exports are projected, except for the period 2000-2010 when higher exports are projected. This mainly reflects higher energy surplus due to lower domestic demand. After 2010, projected levels of exports will not differ significantly between the cases.

In both cases, the anticipated trend towards generally lower exports compared to current levels reflects the assumption that generators will prefer to build smaller power plants close to load centres, rather than to import electricity from remote sources. It also includes the assumption that future firm contracts will be of a shorter duration. The analysis therefore suggests that electricity restructuring will not necessarily lead to higher exports.

Figure 4.5
Electricity Exports and Imports



4.7 PRIMARY ENERGY DEMAND FOR ELECTRICITY PRODUCTION

4.7.1 Heat Rate Assumptions

Heat rates refer to the amount of input energy required to generate one unit of electricity (e.g., the amount of natural gas, expressed in gigajoules (GJ),

Table 4.2
Heat Rate Assumptions
(GJ/GW.h)

	Historical	1997-2005	2006-2015	2016-2025
Natural Gas				
Combustion Turbines	12 000 - 14 000	11 000	10 000	9 000
Combined-Cycle	8 000 - 9 000	7 200	6 000	5 500
Co-generation and DG	5 500	5 500	5 500	5 000
Gas/Oil Steam	10 000 - 12 000	–	–	–
Coal				
Conventional Coal	10 000 - 13 000	–	–	–
Advanced Coal	–	9 000	8 000	7 500
IGCC	–	7 500	7 200	6 000
Biomass	10 000 - 14 000	9 000	9 000	9 000
Nuclear (CANDU)	11 800 - 13 200	–	–	–
Hydro and Wind	3 600	3 600	3 600	3 600

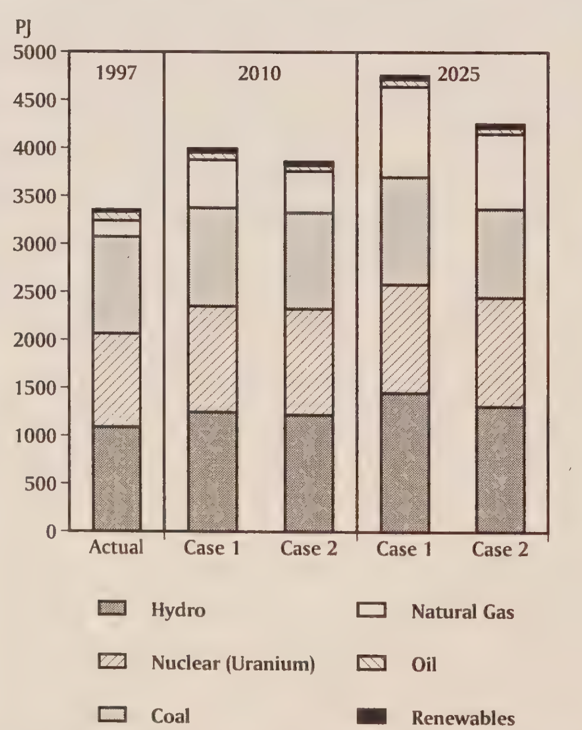
required to produce one GW.h of electricity). For existing units, average historical heat rates were used. For new units, heat rates were assumed to improve over time. Table 4.2 presents the heat rate assumptions related to different generation options.

4.7.2 Primary Demand by Energy Source

Total primary energy demand for electricity generation is expected to increase from 3 398 petajoules (PJ) in 1997 to 4 802 PJ in 2025 in Case 1 and to 4 299 PJ in Case 2 (Figure 4.6). This represents an average annual growth rate of 1.3 and 0.9 percent respectively. Total primary fuel demand grows at a slower pace than total generation, reflecting the assumption of improving heat rates over time.

Electricity generation will provide a growing market for natural gas. Gas demand is expected to rise from 165 PJ in 1997 to 939 PJ in Case 1 and 784 PJ in Case 2 by the end of the projection period. The share of gas in total primary energy demand for electricity production is projected to rise from 5 to 20 percent in Case 1 and to 18 percent in Case 2. The share of coal declines from 30 percent to 24 and 22 percent respectively. In both cases, the shares of hydro, nuclear and oil are also expected to decline, while the share of renewable fuels should rise marginally.

Figure 4.6
Primary Energy Demand for Electricity Generation



4.8 SENSITIVITY ANALYSES

The Board developed and analyzed three sensitivity analyses relating to electricity. The Transmission Sensitivity assumes that an infeed from Labrador to Newfoundland will be built and that there will be no interprovincial transmission capacity constraints. The A&R Sensitivity examines the impact of relatively higher usage of alternative technologies and renewable fuels for electricity generation. The Nuclear Generation Sensitivity examines the impact of an increased demand for gas generation as a result of early nuclear retirements in Ontario.

4.8.1 Transmission Sensitivity

The Transmission Sensitivity was based on Case 1. In this sensitivity, capacity constraints are removed and an infeed to Newfoundland is assumed. Since expected transfers for Case 1, in western Canada, are below capacity, the Transmission Sensitivity was developed for provinces east of Saskatchewan.

Due to the flow of electricity from Labrador to Newfoundland, oil-fired generation, on the island, drops from 5.5 TW.h to 0.3 TW.h. To sustain exports and compensate for reduced transfers from Labrador, hydro capacity increases by about 1 000 MW in Québec, or 3 percent of Québec's generation capacity. Lower flows from Labrador to Québec also lead to generally lower gross interprovincial flows and lower exports compared to Case 1. Only minor changes are projected for Nova Scotia, New Brunswick and Prince Edward Island.

In Case 1, sales from Manitoba to Ontario were constrained by transmission capacity. In this sensitivity, Manitoba is expected to export more to Ontario, about 3.1 TW.h on average annually over the projection period. Generation in Manitoba is projected to be 15 percent higher than in Case 1 while generation in Ontario is about 2 percent lower.

The infeed is expected to reduce primary energy demand since it implies the replacement of thermal generation with more efficient hydro generation. By 2025, total demand for fossil fuels will be 61 PJ lower than in Case 1.

4.8.2 Alternative Technologies & Renewable Fuels Sensitivity

The A&R Sensitivity was developed from Case 2.[5] This sensitivity examined the electricity supply outlook under the assumption of generally higher levels of penetration of alternative technologies and renewable resources (A&R) for electricity generation. In this analysis, A&R include small hydro, wind, and biomass such as wood waste, landfill methane and urban wastes. Photovoltaic applications in Canada are unlikely to reach commercial stage in the foreseeable future and therefore were not considered. Higher penetration of A&R in various end-use markets was also examined (see Chapter 3).

A&R applications are not generally cost-competitive compared to conventional generation sources (large hydro, gas, nuclear and coal). However, the cost of many of these technologies could be greatly reduced over the projection period. Among the A&R options considered, the most imminent appears to be wind energy. Its costs have declined significantly in the last decade but are still higher than those associated with conventional sources. A major weakness related to wind turbines operations is the low availability factor due to the intermittent nature of the resource; thus they are not suitable for base load. Factors which could foster the use of A&R in generation include enhanced consumer preference for "green power", technological progress, fiscal incentives, regulation and legislation.

A&R penetration rates are projected to increase over time by capturing some of the incremental generation. Typically, A&R are assumed to provide up to 20 percent of incremental demand by the end of the projection period. The mix of A&R was estimated by province based on the potential of wind, biomass and small hydro resources.

It was also assumed that integrated gasification combined cycle (IGCC) technology will be used for all coal-fired power plants built after 2010. The higher efficiency of IGCC power plants leads to a reduction in primary demand for coal. By 2025, installed IGCC capacity reaches 6 154 MW, or 4.6 percent of total capacity.

Generation from renewable fuels is expected to rise from 1.5 percent of total generation in 1997 to 4.2 percent by 2025 in the A&R Sensitivity. Québec, Ontario and British Columbia will account for about 75 percent of electricity produced from renewable fuels by 2025. Total renewable fuels production is projected to rise to 31 TW.h by 2025, nearly 4 times higher than the 1997 level.

The increased use of renewable fuels will displace coal and gas generation. By 2025, coal-fired generation will be 9 percent lower than in Case 2, while gas-fired generation will be about 5 percent lower. In 2025, the primary demand for fossil fuels will be 175 PJ less than that in Case 2.

Total renewable fuels generation capacity is projected to increase from 2 112 MW in 1997 to 7 409 MW by 2025, or 5.5 percent of total capacity. By 2025, wind capacity is expected to reach 3 420 MW, biomass 2 376 MW and small hydro 1 613 MW. In Alberta, A&R have the potential to provide the equivalent of one coal-fired unit, while in Ontario they could provide the equivalent of one coal-fired unit and one gas-fired unit. In Québec, the relatively rapid development of wind capacity reflects the government initiative requiring Hydro-Québec to purchase wind power for an extended period.

Electricity exports in the A&R Sensitivity are projected to be slightly higher than in Case 2. Growing generation from A&R, which can only operate when conditions prevail, is projected to lead to higher energy surplus available for exports.

4.8.3 Nuclear Generation Sensitivity

The Nuclear Generation Sensitivity was developed from Case 2. The focus of this sensitivity is to examine the impacts of earlier nuclear plant retirements on the demand for natural gas in Ontario. Specifically, it was assumed that nuclear plants that are currently non-operational will not return to service and that there will be no life extension of in-service units. Combined-cycle gas generation is assumed to replace these facilities. The impact is an additional 12 200 MW of gas-fired capacity by 2025. The corresponding increase in gas-fired generation is 90 TW.h. Primary gas demand is projected to rise by 536 PJ by 2025. The impact on supply, prices and exports of natural gas is discussed in Chapter 5.

5 Detailed results by province are available in *Appendix 4: Electricity*

CHAPTER 5

Natural Gas

5.1 INTRODUCTION

As with previous reports, the natural gas analysis is based on estimates of reserves and resources for Canada and the U.S., estimated supply costs for the major basins, Canadian and U.S. demand and the deliverability of natural gas. The North American Regional Gas Model (NARG) has been used to develop projections of gas flows and prices. Other in-house models have been used to estimate deliverability and well completions in Canada.

5.2 CANADIAN RESERVES AND RESOURCES

Table 5.1 shows the reserves and resources estimates, by region and natural gas source, in Canada for both the Low Cost Supply Case (Case 1) and the Current Supply Trends Case (Case 2).

5.2.1 Conventional Gas - Western Canada Sedimentary Basin

Remaining Established Reserves

The estimates of remaining established reserves for the Western Canada Sedimentary Basin (WCSB) are the same in both cases and are based on figures provided by provincial government agencies in the producing provinces. The unconnected gas estimates in Alberta and B.C. are based on studies carried out over the past three years by various regulatory agencies, with input from industry.

Undiscovered Resources

The Board recognizes that there is uncertainty associated with estimates of undiscovered resources. Historically, the estimates for this category have tended to increase over time due to expanded exploratory areas, more sophisticated estimating techniques and technological advances. Reserves appreciation is included in this category.

Based on comments made in the Round One Consultations, the Board has chosen to use a range of publicly available estimates for the undiscovered resources for the WCSB. The TransCanada Pipeline Ltd.[a] (TCPL) estimate represents the high end of the range and was used in Case 1. TCPL's estimate for Alberta of 138 trillion cubic feet (Tcf) (3.9 trillion m^3) was combined with estimates for B.C. and Saskatchewan to give an undiscovered potential of 176 Tcf (5.0 trillion m^3). Based on a 1996 NEB study,[b] the TCPL estimate was increased by 5 Tcf (142 billion m^3) to account for higher resources in the southern territories (southern portion of the Yukon and NWT). For Case 2, the Canadian Gas Potential Committee[c] (CGPC) estimate of 105 Tcf (3.0 trillion m^3) was used. When these two estimates are added respectively to the cumulative production and the established reserves at the end of 1997, the ultimate resources potential of the WCSB is 335 Tcf (9.5 trillion m^3) for Case 1 and 264 Tcf (7.5 trillion m^3) for Case 2.

5.2.2 Unconventional Gas Resources

Unconventional gas in the WCSB is comprised of coal bed methane (CBM) and tight gas.

Coal Bed Methane

Other agencies and organizations have published estimates of CBM in the WCSB. The Alberta Energy and Utilities Board[d] (EUB) suggested 250 Tcf (7.1 trillion m^3) in its 1992 review as the lower level for in-place resources. TCPL[a] provided an estimate of 214 Tcf (6.1 trillion m^3) of gas-in-place. There is some uncertainty associated with the recovery factor used to derive an estimate of marketable gas for these in-place resources. The National Petroleum Council[e] (NPC) estimated 129 Tcf (3.6 trillion m^3) of marketable CBM. The CGPC[c] estimated a range of 135 to 261 Tcf (3.8 to 7.4 trillion m^3) for marketable CBM, using a recovery factor of 44 to 48 percent. For its estimate of CBM marketable gas potential in the WCSB, the Board has adopted 75 Tcf (2.1 trillion m^3) for both cases, which it views as a relatively conservative estimate. Although CBM is known to be present in other regions of Canada, particularly Nova Scotia and Vancouver Island, no estimates have been prepared for these areas due to the lack of available data.

Tight Gas

There are no recent resources estimates for tight gas. In 1992, the EUB[d] and the NPC[e] provided estimates which range from 89 Tcf to 1500 Tcf (2.5 to 42.5 trillion m^3). Because of uncertain development costs and production technology, no tight gas resources have been included.

5.2.3 Scotian Shelf

The Scotian Shelf reserves and resources estimates were provided by the Canada-Nova Scotia Offshore Petroleum Board. Established reserves of 3 Tcf (85 billion m^3) and the discovered resources of 2 Tcf (57 billion m^3) are in the vicinity of Sable Island and are

Table 5.1
Canadian Ultimate Potential Gas Resources
(Tcf Year-end 1997)[3]

	Discovered Marketable Resources					
	Cumulative Production	Remaining Established Reserves	Unconnected Reserves[1,2]	Total	Undiscovered Resources	Ultimate Resources Potential
Case 1						
Total Canada	103	51	44	198	535	733
WCSB Conventional	102	48	9	159	176	335
Alberta	86	38	8	132	138	270
British Columbia	12	7	1	20	30	50
Saskatchewan	4	3	0	7	2	9
Southern Territories	<1	<1	0	<1	6	6
WCSB Unconventional	0	0	0	0	75	75
Other Conventional	1	3	2	6	14	20
Ontario	1	<1	0	1	1	2
Scotian Shelf	0	3	2	5	13	18
Frontier	0	0	33	33	270	303
Grand Banks/Labrador	0	0	9	9	36	45
Mackenzie/Beaufort	0	0	9	9	55	64
Arctic Islands	0	0	14	14	80	94
Other Yukon/NWT	0	0	1	1	10	11
Other Frontier	0	0	0	0	89	89
Case 2						
Total Canada	103	51	44	198	464	662
WCSB Conventional	102	48	9	159	105	264
Alberta	86	38	8	132	82	214
British Columbia	12	7	1	20	17	37
Saskatchewan	4	3	0	7	2	9
Southern Territories	<1	<1	0	<1	4	4
WCSB Unconventional	0	0	0	0	75	75
Other Conventional	1	3	2	6	14	20
Ontario	1	<1	0	1	1	2
Scotian Shelf	0	3	2	5	13	18
Frontier	0	0	33	33	270	303
Grand Banks/Labrador	0	0	9	9	36	45
Mackenzie/Beaufort	0	0	9	9	55	64
Arctic Islands	0	0	14	14	80	94
Other Yukon/NWT	0	0	1	1	10	11
Other Frontier	0	0	0	0	89	89

1 Unconnected reserves are part of the established reserves that are not connected to a transportation system

2 For Other Conventional and Frontier Resources, this refers to Discoverered Resources

3 This table is available in metric units in *Appendix 5: Natural Gas*.

associated with the development of the Sable Gas Project. For the entire Scotian Shelf, the estimate of undiscovered resources is 13 Tcf (368 billion m^3) for both cases.

5.2.4 East Coast Frontier

The east coast frontier region includes the Grand Banks and Labrador. In both cases, 9 Tcf (255 billion m^3) is included in the discovered resources category and a further 36 Tcf (1 trillion m^3) in the undiscovered category. These estimates were prepared by the Canada-Newfoundland Offshore Petroleum Board.

5.2.5 Northern Frontier

The Mackenzie/Beaufort and Arctic Islands resources estimates are based on the 1994 Report[f] and an NEB update published in 1998.[g] Estimates for the Mackenzie/Beaufort region are 9 Tcf (255 billion m^3) of discovered resources and 55 Tcf (1.6 trillion m^3) of undiscovered resources for both cases. The Arctic Islands and other areas of the territories are estimated to contain 15 Tcf (425 billion m^3) of discovered resources and a further 90 Tcf (2.6 trillion m^3) of undiscovered resources.

5.2.6 Other Frontier Regions

The other frontier regions include George's Bank, the Laurentian Basin, South Grand Banks, Hudson Bay and offshore B.C. and do not have any discovered resources, which is an indication of their lack of maturity. The estimates for each area were prepared by the Geological Survey of Canada and adjusted by the NEB, but have not been updated since the early 1980s. Some parties indicated that a more detailed breakdown of these resources should be provided. However, because of the lack of new data, the Board does not believe that reasonable regional estimates can be made at this time.

5.3 U.S. RESERVES AND RESOURCES

The Board does not prepare estimates of U.S. reserves and resources; rather, it relies on estimates from U.S. agencies, notably the U.S. Geological Survey (USGS)[h] and the Minerals Management Service (MMS)[i] which have been used for Case 2 (Table 5.2). For Case 1, the estimate of the undiscovered resources was developed by increasing the Case 2 value by the same proportion assumed between Case 1 and Case 2 in the WCSB. Interestingly, the resulting estimate for Case 1 is similar to that prepared by the Gas Research Institute (GRI).[j]

5.4 NORTH AMERICAN REGIONAL GAS MODEL

The NARG model (Figure 5.1) has been used to project production, exports, pipeline corridor flows and prices. The assumptions behind this model are fully described in the 1994 Report.[f] Some enhancements and updates to the model have been made since the last report:

Table 5.2
U.S. Lower 48 Ultimate Potential Gas Resources
(Tcf Year-end 1997)

	Discovered Marketable Resources					
	Cumulative Production	Remaining Established Reserves	Reserves appreciation	Total	Undiscovered Resources	Ultimate Resources Potential
Case 1						
Total U.S. Lower 48	847	166	245	1 258	1 137	2 395
Conventional	841	151	235	1 227	802	2 029
Unconventional	5	11	10	26	250	276
Deep Offshore	1	4	0	5	85	90
Case 2						
Total U.S. Lower 48	847	166	245	1 258	667	1 925
Conventional	841	151	235	1 227	479	1 706
Unconventional	5	11	10	26	140	166
Deep Offshore	1	4	0	5	48	53

Figure 5.1
NARG Model Pipeline Schematic

- A toll discounting feature has been added on underutilized pipeline corridors.
- The network has been updated to include approved pipelines and potential future corridors.
- The NOVA system has been divided into zones to reflect the proposed tolling.
- A backstop price[1] of US$3.50/Mcf has been used.

As with most complex models, care should be taken in interpreting the results from the NARG model. The output is more indicative of trends, rather than precise results.

5.5 SUPPLY COST

The methodology used for calculating supply cost is similar to that used in the 1994 Report.[f] Costs include exploration and development expenses; operating costs; taxes; royalties; and a real rate of return to the producer of six percent.

In Case 1, it is assumed that technology will reduce costs and increase finding rates at a more rapid pace than in Case 2. The rate of improvement is 5 percent per year in Case 1 and 2 percent per year in Case 2. In both cases, cost reductions are limited to 50 percent of the initial value. The specific technologies are not defined. Improvements to existing technologies, such as seismic, drilling, well completions and horizontal wells are expected to continue. Also, new technologies are likely to be developed, particularly in the deep offshore areas and for unconventional gas.

In Case 1, supply costs in the WCSB rise gradually to about US$2.00/Mcf and then increase more rapidly due to declining reserves per well (Figure 5.2). In Case 2, similar trends to Case 1 are observed, but costs are, on average, about 25 percent higher. Supply costs for other regions are provided in *Appendix 5: Natural Gas*.

5.6 WCSB DELIVERABILITY – CONVENTIONAL RESOURCES

The NARG model is a generalized model and it cannot readily project deliverability based on specific well data, nor is it able to project drilling activity. For this analysis, the Board has developed an in-house model to refine the NARG output. In the deliverability model, different assumptions are developed for three reserves categories: established, unconnected and reserves additions. Wells are added from each of the three categories, based on their expected performance and supply cost, to match the production output from NARG.

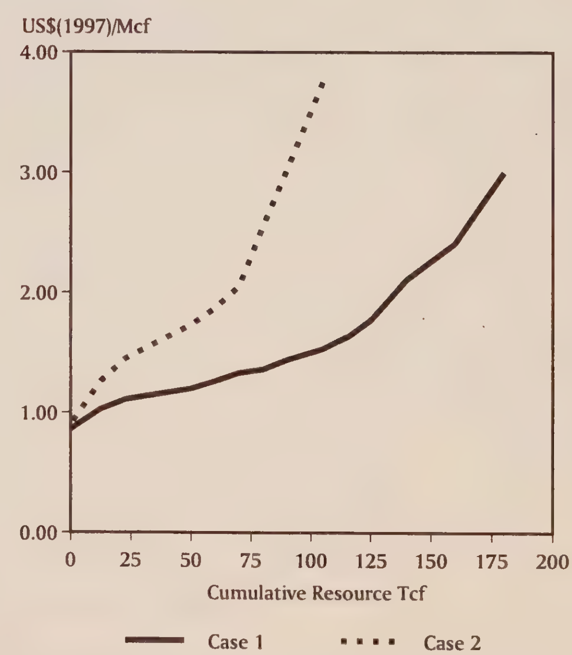
5.6.1 Established Reserves

It is assumed that remaining established reserves are producing at capacity. These wells were grouped according to the year they were placed on production. Decline rates for each vintage group were determined. Future deliverability was determined by extrapolating these declines from 1997 production rates.

5.6.2 Unconnected Reserves

Unconnected reserves are estimated to be 8 Tcf in Alberta and 1 Tcf in B.C. During the Round Two Consultations, concerns were raised that the connection rate for this category was too aggressive; consequently, the connection period has been adjusted from 12 to 19 years, starting in 2000 (Table 5.3). The assumed well characteristics are defined in Table 5.4.

Figure 5.2
WCSB Supply Costs - Undiscovered Resources



1 Backstop price refers to the cost of a substitutable fuel that, for the model's purposes, is infinitely available. It tends to provide a cap on natural gas prices.

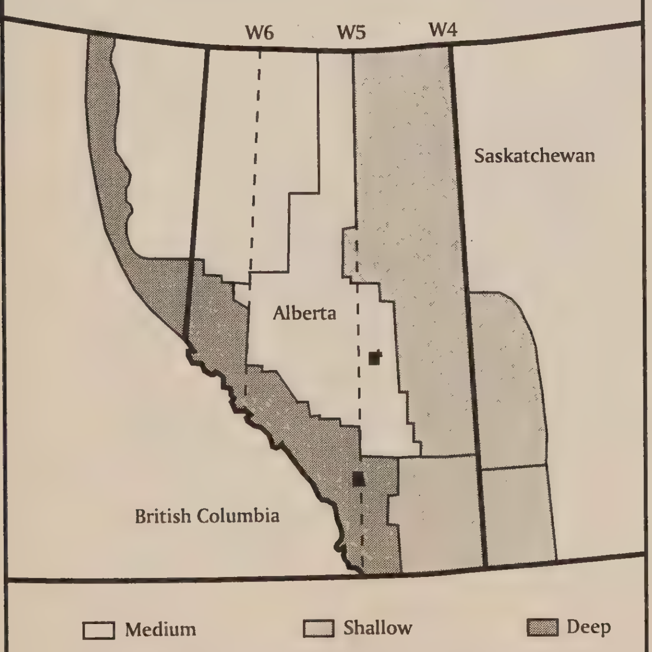
5.6.3 Reserves Additions

For reserves additions, each province was divided into areas representing similar reservoir depths and drilling costs. For simplicity, these have been called shallow, medium and deep areas (Figure 5.3). The quantity of undiscovered resources for each area and province is shown in Table 5.4. Note that no shallow gas is included in B.C. and neither medium nor deep gas is included in Saskatchewan.

Table 5.3
Schedule for Unconnected Wells

Year	Wells Connected (percent per year)
1	1
2	2
3 and 4	5
5 and 6	8
7, 8 and 9	10
10, 11 and 12	8
13 and 14	5
15 and 16	2
17, 18 and 19	1

Figure 5.3
Undiscovered Resources
Shallow, Medium and Deep Areas



The initial production, reserves per well and decline rates of wells connected over the last three years have been used to project the deliverability from future discoveries. These characteristics, except for the reserves per well, are assumed to remain constant over the projection period and are the same for both cases. It is assumed that the reserves per well will decline at 1 percent per year in Case 1 and at 1.5 percent per year in Case 2. This results in a reduction in the average reserves per well of about 25 percent when 85 percent of the undiscovered resources have been connected. The average reduction in reserves per well is similar in both cases.

Location for future wells follows current drilling trends in the early years, but later shifts to areas with the highest resources potential, typically in the shallow and medium depth areas. This is consistent with the NARG process of selecting a combination of undiscovered resources from each area, based on the relative supply costs. In the deliverability model, some judgement is applied to the number of completions when the cumulative reserves additions approach the estimate of undiscovered resources.

Table 5.4
Typical New Well Characteristics - Both Cases

Region and Category	Initial Productivity (MMcf/d)	Reserves per Well (Bcf)	Decline Rate (percent)	Undiscovered Resources Case 1 (Tcf)	Undiscovered Resources Case 2 (Tcf)
Alberta					
Unconnected	1.0	1.1	33	8	8
Shallow New	0.5	0.5	33	50	26
Medium New	1.2	1.2	35	76	46
Deep New	2.5	3.9	23	13	11
B.C. and Southern Territories					
Unconnected	1.9	4.2	17	1	1
Medium New	2	4.0	18	24	14
Deep New	5	7.3	25	13	7
Saskatchewan					
Shallow New	0.5	0.5	35	2	2

5.7 RESULTS AND ANALYSIS

All prices are in 1997 constant Canadian dollars, unless otherwise noted.

5.7.1 WCSB Conventional Production

WCSB conventional production peaks at 21.6 billion cubic feet per day (Bcf/d) (612 million m³/d) in 2013 for Case 1 and 18.9 Bcf/d (535 million m³/d) in 2008 for Case 2 (Figure 5.4). In both cases, the medium depth pools provide most of the incremental production as approximately 50 percent of the undiscovered gas is expected to be found in those pools.

In both cases, about 95 percent of the established reserves are produced by 2025. In Case 1, 82 percent of the undiscovered resources is produced, whereas in Case 2, 95 percent is produced.

Alberta production peaks at 17.9 Bcf/d (507 million m³/d) in Case 1 and 15.2 Bcf/d (430 million m³/d) in Case 2. In Case 1, B.C. production rises throughout the study period reaching 3.8 Bcf/d (108 million m³/d). In Case 2, this production peaks at 3.4 Bcf/d (96 million m³/d) in 2013 and declines moderately thereafter. In Saskatchewan, production peaks at about 0.8 Bcf/d (23 million m³/d) in 2005 in both cases and then declines. Detailed production by province is provided in *Appendix 5: Natural Gas*.

5.7.2 WCSB Gas Well Completions

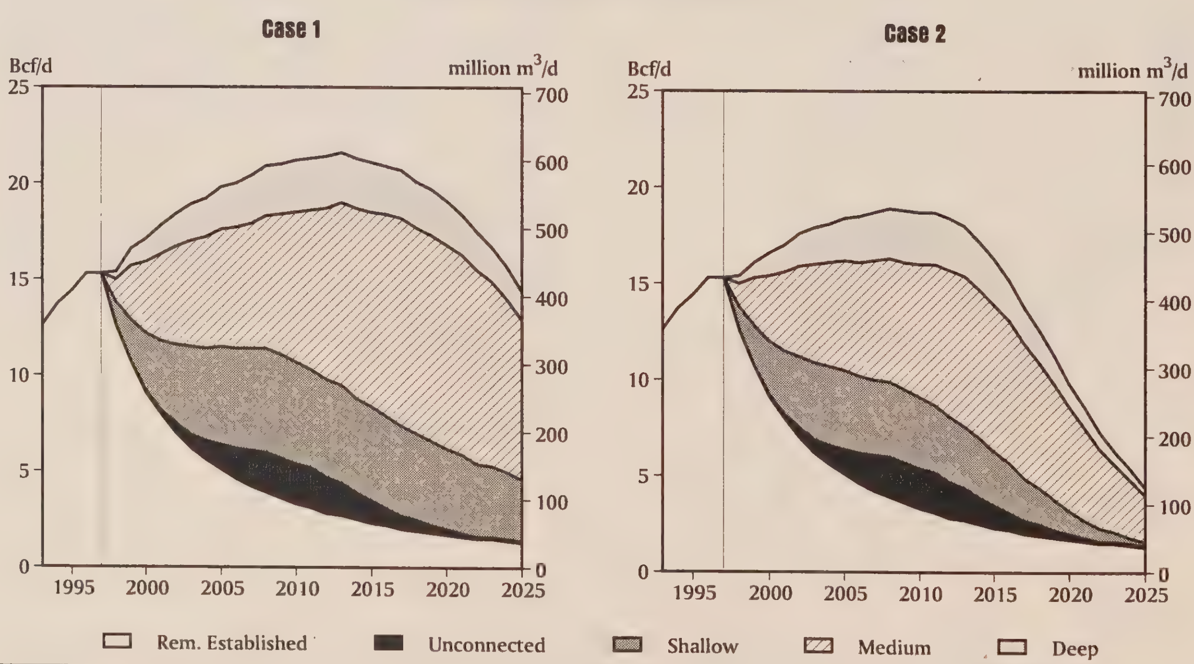
Successful conventional gas well completions in the WCSB rise to 7 700 by 2013 in Case 1. The Case 2 completions peak at about 6 000 in 2011, reflecting the lower resources assumption (Figure 5.5). The number of wells drilled will be higher because dry holes will increase the count; however, this will be partially offset by multiple completions in the same well. Based on an average success rate of 70 percent, the total wells drilled would peak at about 10 000 and 8 000 for Case 1 and Case 2 respectively.

5.7.3 Total Canadian Production

In Case 1, as conventional production from the WCSB declines, most of the new supply is provided by unconventional gas, principally CBM, reaching about 10 Bcf/d (283 million m³/d) by 2025. Scotian Shelf production begins in 2000 at 0.5 Bcf/d (14 million m³/d), rising to about 2 Bcf/d (57 million m³/d) by 2025. Total Canadian production rises steadily to about 27 Bcf/d (765 million m³/d) (Figure 5.6).

In Case 2, unconventional production reaches 14 Bcf/d (397 million m³/d). The Scotian Shelf produces about 1.2 Bcf/d (34 million m³/d) by 2025. Mackenzie Delta production is expected to start in 2017 and rise to

Figure 5.4
WCSB Conventional Production



just over 1.5 Bcf/d (42 million m³/d) by 2025. Total production rises to about 23 Bcf/d (652 million m³/d) in 2018 and declines slightly thereafter. This is due to a decline in exports as Canadian supply is less competitive than U.S. supply in this case.

In both cases, about one third of the Scotian Shelf gas is expected to be used in Atlantic Canada primarily in the power generation sector. Small volumes could flow into Québec, but the majority of the remaining production is expected to be exported (see Section 5.7.5).

Some concerns were expressed during the consultations that the production from unconventional resources was optimistic. CBM supply becomes a significant component of production in 2015 in Case 1 and 2013 in Case 2. At that time, the plantgate prices realized by this source are about $(1997)2.00 and $2.60 per gigajoule for Case 1 and Case 2 respectively. At these prices, with the appropriate technological improvements, there should be an incentive to pursue these prospects.

To date there has been little CBM development in western Canada. There is active research being conducted by various government agencies and industry[2] which could advance the development of CBM. Alternatively, there could be sooner and more rapid

Figure 5.5
WCSB Conventional Gas Well Completions

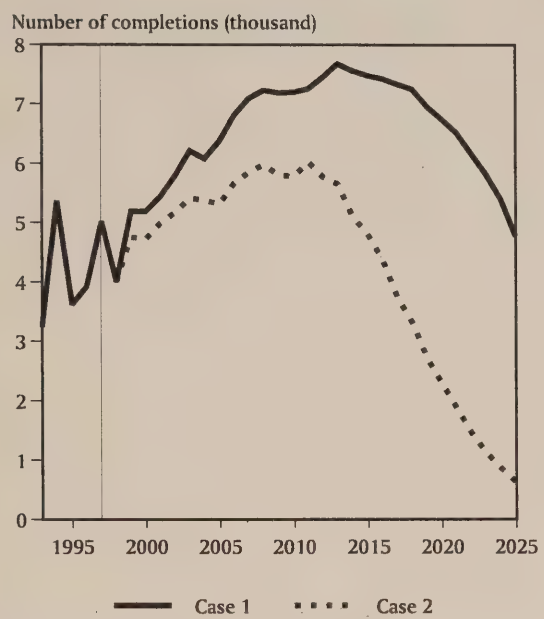
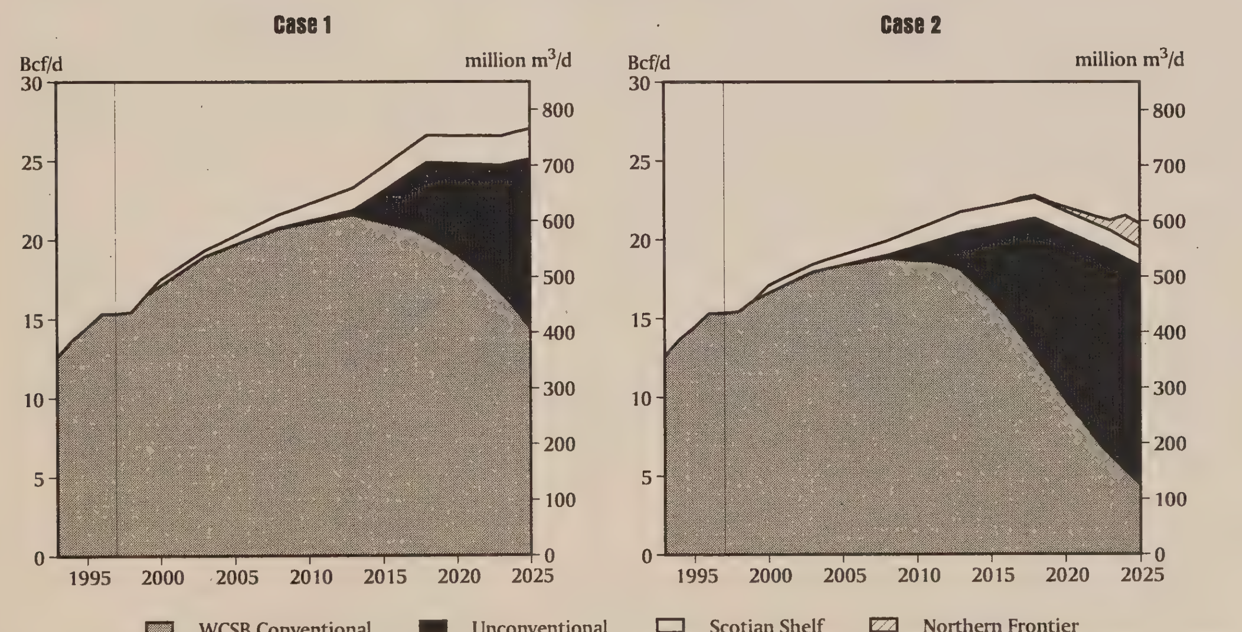


Figure 5.6
Total Canadian Production



2 The Panel on Energy R&D (PERD) is sponsoring two programs: Coal Bed Methane and Alternative Coal Use (PERD No 511004); and Sustainable Development of Coal Bed Methane; A Life-Cycle Approach to Production of Fossil Energy.

development of the northern frontier resources. Under that circumstance, frontier gas could displace some of the potential CBM supply.

Although the Board recognizes significant resources in the eastern frontiers, no production has been included from this region due to the remoteness from major markets. It is not expected that a major pipeline would be constructed from the Grand Banks to continental North America within the study period. However, it is possible that the associated gas from oil developments in this region could reach local markets, displacing heavy fuel oil in the power generation sector. In order to achieve this, some technological advances would be required. The two most promising technologies are a compressed gas transportation system and a gas-to-liquids process (see Section 5.9).

5.7.4 Prices

Technological improvements and resources assumptions are the primary influences on the price projections. In Case 1, these are more aggressive than in Case 2, which leads to higher prices in the latter case. Nevertheless, depletion of conventional gas resources leads to rising prices in both cases.

Plantgate Prices

In Case 1, Alberta prices remain relatively flat, in real terms, at about $1.65 per gigajoule (GJ) until 2010 when they start to rise and reach about $2.60/GJ by 2025. Scotian Shelf prices start at $2.50/GJ and then rise to $3.50/GJ (Figure 5.7). In Case 2, prices rise steadily to about $3.60/GJ for Alberta. Scotian Shelf prices rise to over $4.35/GJ by 2025. In both cases, B.C. prices will tend to be similar to those of Alberta.

Annual price increases average about 1.5 percent and 2.8 percent for Case 1 and Case 2 respectively. The slight decline in the early years is due to the assumption of an appreciating Canadian dollar compared to the U.S. currency and the fact that, in 1997, the last year of historical data, gas prices were unusually higher than in prior years.

Export Prices

Export prices show steady increases in both cases. In Case 1, they reach about US$2.50/Mcf in 2025 for Monchy and about US$3.60/Mcf for Niagara (Figure 5.8). In Case 2, they reach US$3.35/Mcf for Monchy and US$4.40/Mcf for Niagara by 2025. The prices at Kingsgate tend to follow the prices at Monchy.

Figure 5.7
Plangate Prices

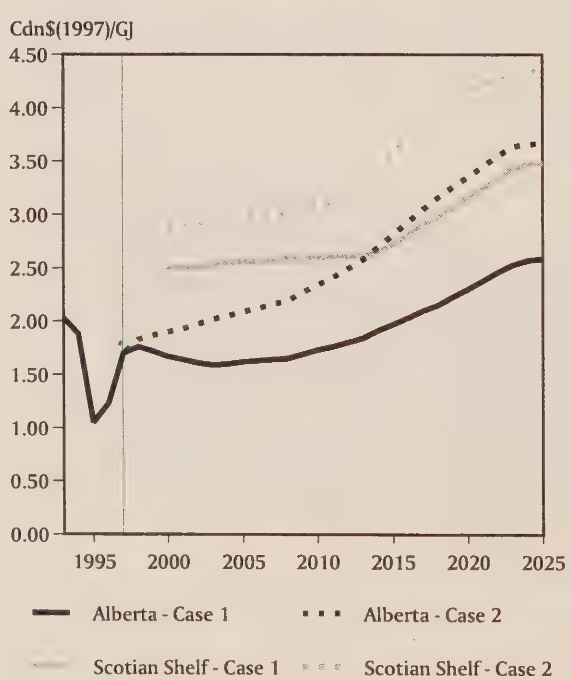
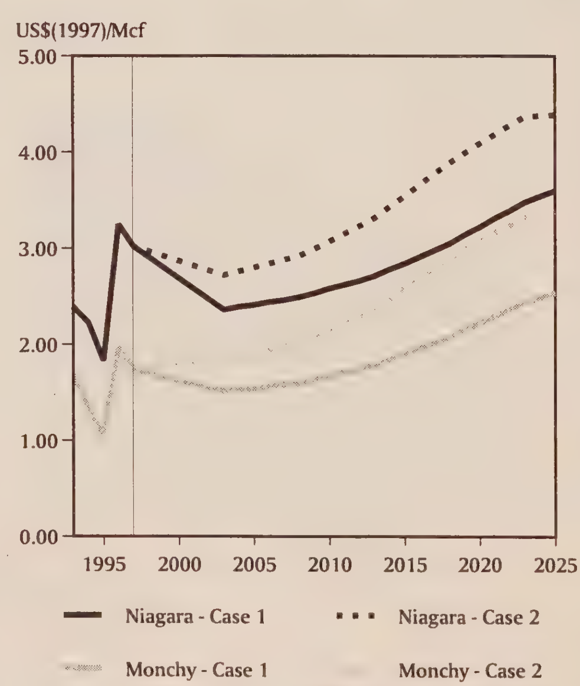


Figure 5.8
Export Prices



Price Differentials

Price differentials between Alberta and major U.S. markets are similar for both cases. The Alberta/Gulf of Mexico differential is about US$0.35/Mcf, which is in the range expected for a relatively well integrated North American natural gas market (Figure 5.9).

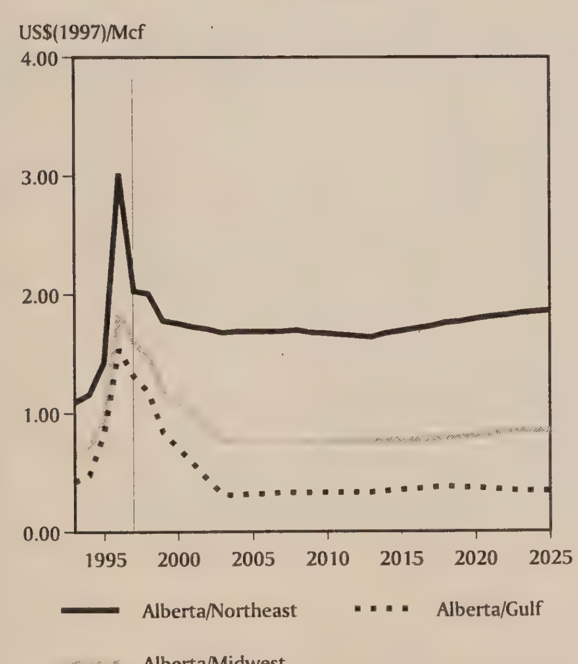
The Alberta/Midwest differential is about US$0.75/Mcf and the Alberta/Northeast difference is about US$1.60/Mcf. Both of these differentials are close to the assumed tolls on these corridors, indicating that the markets are relatively well balanced.

5.7.5 Exports

Total exports would reach a maximum of about 5 Tcf/year in 2018 before declining moderately to 4.6 Tcf/year in Case 1, whereas the peak for Case 2 is 4.4 Tcf/year in 2013 and the decline is steeper to 3.5 Tcf/year by 2025 (Figure 5.10). While there are some regional differences, Canadian exports in both cases would account for about 18 percent of U.S. demand at the peak level of exports and decline to about 13 percent by 2025.

Exports of Canadian gas to the Pacific Northwest are expected to remain fairly constant throughout the projection period at 0.4 Tcf/year for both cases. In Case 1, exports to California decline slightly from 0.74 Tcf/year to 0.66 Tcf/year; the decline is greater in Case 2, to 0.50 Tcf/year by 2025. This is due to sharp production increases in the Rocky Mountain region, which displace some Canadian gas, and to a strong demand pull for Canadian gas from California to the U.S. Midwest.

Figure 5.9
Price Differentials



Exports to both the Midwest and Northeast (New England and Mid-Atlantic) increase due to higher demand in the power generation markets in those regions. The Midwest reaches a peak of 2.64 Tcf/year in Case 1 before declining to 2.35 Tcf/year. The peak is somewhat lower in Case 2, at 2.15 Tcf/year, and the decline is steeper to 1.60 Tcf/year by 2025.

For the Northeast, exports reach 1.2 Tcf/year in both cases. However, in Case 2, exports decline slightly to about 1 Tcf/year. In Case 1, about 40 percent of the Northeast exports are supplied from the Scotian Shelf by 2025; while in Case 2, this figure is about 30 percent.

Corridor Capacities

No increase in export capacity to the California market is expected since flows are projected to be below capacity in both cases (Figure 5.11).

In the western portion of the Midwest, capacity in 2000 includes the 1998 expansion of the Foothills/Northern Border pipeline system and the construction of the Alliance Pipeline. By 2010, a further increase of about 1.2 Bcf/d is indicated in Case 1 and one of about 0.5 Bcf/d in Case 2. This capacity would likely be sufficient in 2025 in Case 2, but Case 1 would require a further expansion of about 0.7 Bcf/d. Not all of the Midwest capacity would be used to satisfy demand in that market; some gas may flow to other markets.

No expansion to the eastern portion of the Midwest is expected over the study period as most of the incremental gas is flowing on the western Midwest corridor through Chicago.

A capacity increase of 0.6 Bcf/d by 2000 is assumed in the Northeast corridor. This capacity is sufficient in both cases until the end of the projection period. The apparent underutilization of this corridor towards the end of the outlook is caused by strong exports from the Scotian Shelf to the Northeast, which displaces gas from the WCSB. The Scotian Shelf route shows very strong

growth in both cases. Capacity almost triples to 1.35 Bcf/d in Case 1 and more than doubles to 1.1 Bcf/d in Case 2.

In Canada, the TCPL system has an average capacity of 7.3 Bcf/d on the western section, between Empress and Emerson. On the central section, east of Emerson, the capacity drops to about 4 Bcf/d. In Case 1, the western section could increase to about 9 Bcf/d by 2025 and the central section to about 4.5 Bcf/d. In Case 2, no increase in capacity is anticipated on either section. The

Figure 5.10
Canadian Exports by Region

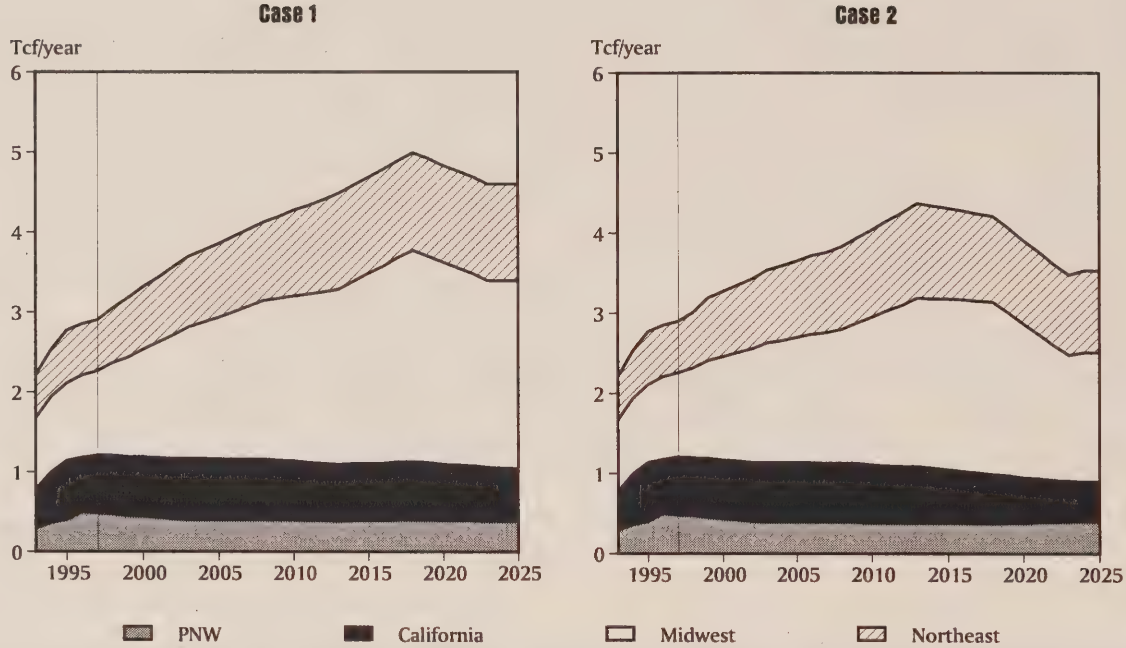
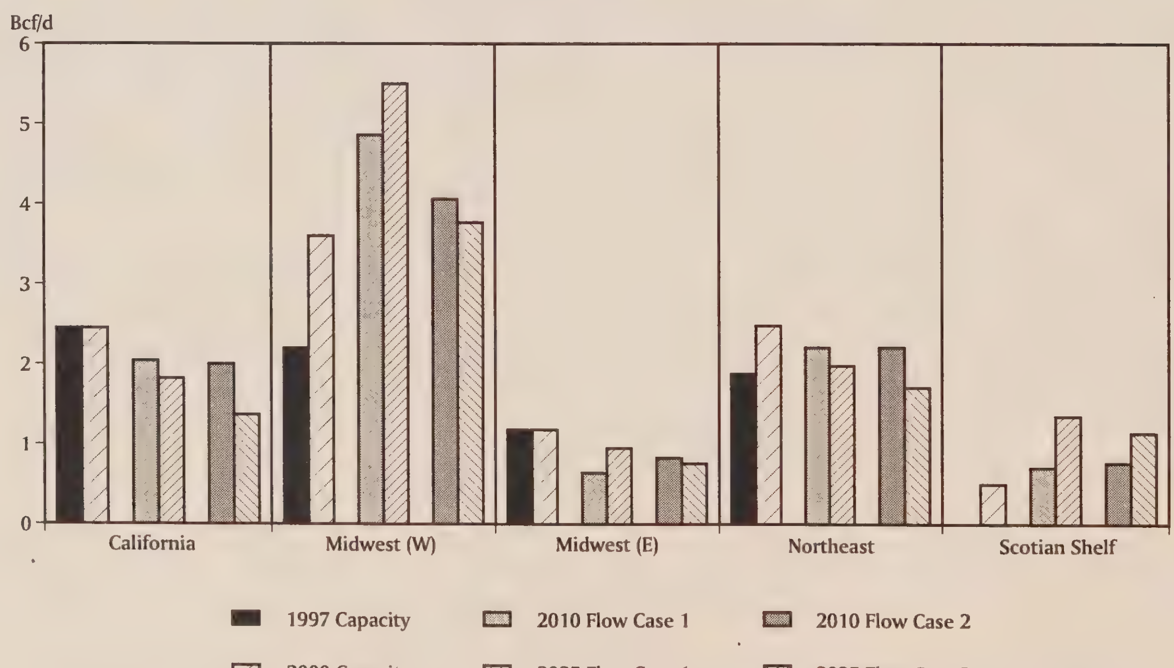


Figure 5.11
Export Corridor Capacity and Flow



increase in capacity could be greater due to incremental exports.

5.7.6 U.S. Demand and Production

U.S. Demand

The GRI Baseline Projection was used to estimate U.S. demand. The 1996 version was chosen as it more closely resembles the Board's assumptions with respect to economic growth and oil prices. The principal area of difference with more recent GRI studies is the gas demand for power generation, which is one of the sensitivities analyzed in this report (Section 5.8). GRI projections were extrapolated past 2015, to match the study period of this report.

In Case 1, demand reaches 32 Tcf/year in 2025, including pipeline fuel. Most of the increase is in the power generation sector, which reaches 8.5 Tcf/year by 2025 (Figure 5.12). Currently, gas use for power generation is about 4 Tcf/year and total demand is about 22 Tcf/year.

In Case 2, the GRI estimates were modified by reducing demand in each end-use sector by similar proportions to those projected between Case 1 and Case 2 in Canada (see Chapter 3). This resulted in a demand of 29 Tcf in 2025 of which about 7.5 Tcf is in the power generation sector. The average annual growth rates are 1.5 percent for Case 1 and 1.2 percent for Case 2. On a regional basis, the strongest growth is in the South and Northeast at 2 and 2.5 percent per year, respectively; the lowest growth areas tend to be California and the Midwest, at about 1 percent per year.

U.S. Production

In Case 1, total U.S. annual production reaches 28 Tcf, compared to almost 26 Tcf in Case 2 (Figure 5.13). Currently, annual U.S. production is about 18.5 Tcf, of which almost half comes from the Gulf of Mexico region. In both cases, strong increases from the Gulf of Mexico, especially deep water production, and the Rocky Mountain regions are anticipated. Gulf of Mexico production increases to 13.6 Tcf and 10.3 Tcf by 2025 in Case 1 and Case 2 respectively. The Rocky Mountain region is expected to increase to 3.7 Tcf/year in Case 1 and 3.1 Tcf/year in Case 2. The Anadarko and Permian basins are expected to show declines.

U.S. Prices

Gulf Coast prices for Case 1 are expected to be about US$1.90/Mcf until 2010 and then rise to US$2.90/Mcf by 2025. For Case 2, Gulf prices are expected to be about US$0.60 to US$0.70/Mcf higher than in Case 1, reaching about US$3.60/Mcf by the end of the study period.

Figure 5.12
U.S. Natural Gas Demand

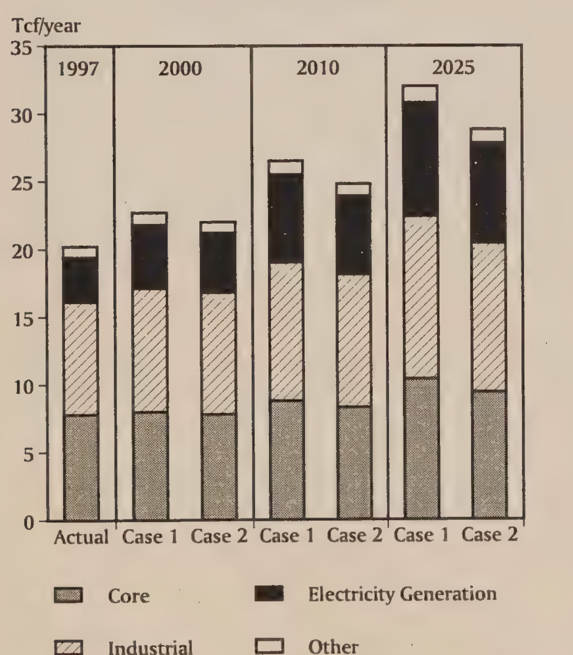
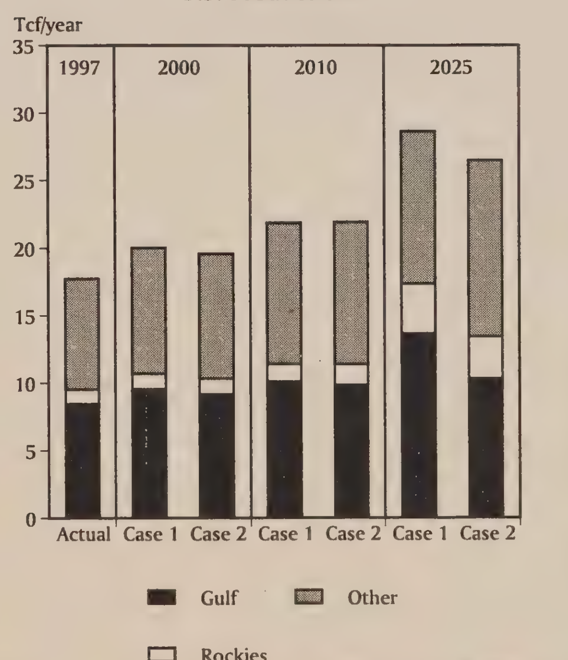


Figure 5.13
U.S. Production



The price differentials between most U.S. markets support the tolling assumptions, except for the Midwest to the Mid-Atlantic corridor. The average differential on this route is about US$0.40 to US$0.50/Mcf in both cases, which appears to be insufficient to cause gas to flow from the Midwest to the Mid-Atlantic, based on current tolling information.

5.8 SENSITIVITY ANALYSES

Two sensitivities impacting Canadian natural gas production, prices and exports were developed: The Oil Price Sensitivity (US$14 and US$22 per barrel); and the Nuclear Generation Sensitivity.

5.8.1 Oil Price Sensitivity

The impact of lower oil prices ($14 Sensitivity) was developed from Case 2, while the impact of higher prices ($22 Sensitivity) was developed from Case 1 (Table 5.5).

By 2025, in the $14 Sensitivity, natural gas plantgate prices are lower by 5 percent in Alberta and 7 percent in the U.S. In the $22 Sensitivity, prices are 4 percent higher in both the U.S. and Canada.

Canadian gas production and exports decline by about 9 percent in the $14 Sensitivity by the end of the projection; while they increase by about 3 percent in the $22 Sensitivity.

In the $14 Sensitivity, fuel switching is not measurable in Canada, but the equivalent of 3.6 Tcf moves to oil from gas in the U.S. In the $22 sensitivity, the shift from oil to gas is equivalent to 0.1 Tcf in Canada and 0.8 Tcf in the U.S.

The differences in natural gas prices, production and exports is caused by the substitution to, or from, oil in the markets where gas and oil compete. The substitution is based on the relative prices of each commodity in those markets.

5.8.2 Nuclear Generation Sensitivity

In this sensitivity, it is assumed that none of the currently non-operational nuclear plants in Ontario return to service. Also, early nuclear retirements are assumed in the U.S. By 2025, this leads to higher gas demand of 0.6 Tcf/year (13 percent) in Canada and 2.3 Tcf/year (7 percent) in the U.S. The Nuclear Generation Sensitivity was developed from Case 2, similar differences could be expected from Case 1 (Table 5.6).

Only modest increases in prices and production are observed in 2010, as the major impact of this sensitivity occurs after that time. By 2025, the Alberta Border price has risen by about 18 percent and the Gulf Coast price has increased by 10 percent. Canadian production and exports increase by almost 10 percent, as a result of higher prices and demand. Most of the increase in Canadian production supplies the incremental demand

Table 5.6
Nuclear Generation Sensitivity

	Case 2 (levels)		Nuclear Sensitivity (difference from Case 2)	
	2010	2025	2010	2025
Alberta Border Price ($/GJ)	2.60	3.86	0.14	0.69
Gulf Price (US$/Mcf)	2.36	3.51	0.15	0.35
Canadian Production (Tcf/year)	7.5	8.0	0.3	0.9
Canadian Exports (Tcf/year)	4.0	3.3	0.1	0.3
US Production (Tcf/year)	22.0	26.5	0.2	1.9

Table 5.5
Oil Price Sensitivity

	Case 2 (levels)		$14 Sensitivity (difference from Case 2)		Case 1 (levels)		$22 Sensitivity (difference from Case 1)	
	2010	2025	2010	2025	2010	2025	2010	2025
Alberta Border Price ($/GJ)	2.60	3.86	(0.14)	(0.20)	1.99	2.75	0.04	0.10
Gulf Price (US$/Mcf)	2.36	3.51	(0.14)	(0.24)	1.89	2.75	0.03	0.10
Canadian Production (Tcf/year)	7.5	8.0	(0.1)	(0.6)	8.1	9.9	0	0.3
Canadian Exports (Tcf/year)	4.0	3.3	(0.1)	(0.3)	4.3	4.5	0	0.2
Canadian Fuel Switching to oil (Tcf/year)	-	-	0	0	-	-	0	(0.1)
U.S. Fuel Switching to oil (Tcf/year)	-	-	0.4	3.6	-	-	0	(0.8)

in Ontario. U.S. production increases to meet the U.S. incremental demand, supplemented by Canadian exports.

The price increase in Canada would affect all gas consuming sectors and could increase the cost of gas-fired electricity generation by 10 to 14 percent.

5.9 NEW TRANSPORTATION TECHNOLOGY

5.9.1 Compressed Gas Transportation

A new concept for gas transportation has been developed by Cran and Stenning Technology Inc.[k] This process compresses gas into small diameter coiled tubing, called "Cosselles," that are mounted on ships. When the vessel is full, it can also be used as a storage facility. This system may be cost effective for relatively small volumes of gas; 300 MMcf/d could be shipped 1000 miles for about US$1.50/Mcf. The technology could be applied to the associated gas at Hibernia and other offshore oil production on the Grand Banks. This gas could then be delivered to a power generation facility located close to a port.

5.9.2 Gas to Liquids Conversion

The technology to convert natural gas to liquid fuels, the Fischer-Tropsch process, was developed in the 1920s. The process produces a high quality feedstock that can be refined into products such as low sulphur diesel. Until recently, widespread application has been hindered by costs. In 1998, several small scale projects, in the 50 to 100 thousand barrels per day range, have been implemented, including those by Shell in Bangladesh and Syntroleum in Washington State. BP-Amoco has also proposed that the gas associated with the Prudhoe Bay oil may be brought to market by this process and Texaco is considering two large scale projects in Brazil and the Shetland Islands. It has been suggested that the process could be viable with oil prices in the range of US$15 to $20 per barrel, depending on the value ascribed to the natural gas feedstock. This technology could be used to market "stranded" gas in remote regions, which tends to have a low value. In Canada, it could apply to the associated and non-associated gas in the Grand Banks of Newfoundland and Labrador.

5.10 COMPARISON TO OTHER PROJECTIONS

In order to put the Board's outlook into context, comparisons to the projections of other agencies and organizations are provided in Table 5.7. Care should be taken with these comparisons as the underlying assumptions may vary from one projection to another.

The comparative projections are: Gas Research Institute - Baseline Projection of U.S. Energy Supply and Demand 1999 Edition (GRI); Energy Information Administration - Annual Energy Outlook 1999 (EIA); Petroleum Industry Research Associates - 1998 forecast (PIRA); and Natural Resources Canada - Canada's Energy Outlook 1996, updated October 1998 (NRCan).

In 2010, the Case 1 projection of the Alberta border price is significantly lower than that of other outlooks. In Case 2, the price is close to that of PIRA and less than 10 percent higher than that of NRCan. Similar differences for U.S. prices may be observed. The Board's projections for Canadian and U.S. production, and Canadian exports, fall within the range of the other projections.

Table 5.7
Table of Comparisons

2010	GRI	EIA	PIRA[1]	NRCan	NEB Case 1	NEB Case 2
Alberta Price ($/GJ)	n/a	n/a	2.33[2]	2.15[3]	1.73	2.34
U.S. Price (US$/Mcf)	2.10	2.52	2.77	2.05	1.88	2.35
Canadian Production (Tcf/year)	n/a	n/a	8.8	7.0	8.1	7.5
U.S. Production (Tcf/year)	25.3	23.8	22.5	n/a	23.6	22.0
Canadian Exports (Tcf/year)	3.6	4.2	4.9	3.8	4.2	4.0
2020						
Alberta price ($/GJ)	n/a	n/a	n/a	2.13[3]	2.30	3.35
U.S. Price (US$/Mcf)	2.30	2.68	n/a	2.05	2.40	3.18
Canadian Production (Tcf/year)	n/a	n/a	n/a	7.3	9.7	8.0
U.S. Production (Tcf/year)	28.3	27.3	n/a	n/a	26.4	24.3
Canadian Exports (Tcf/year)	3.8	4.9	n/a	3.8	4.8	3.8

1 PIRA forecast ends in 2010
2 Estimated from nominal US$/MMBTU
3 Adjusted to 1997 dollars

The Board's projections of Canadian gas prices in 2020 are substantially higher for both cases than that of NRCan. The Case 1 projection of U.S. prices falls within the range of those of GRI and EIA, but the Case 2 projection is about 18 percent higher. NEB projections of Canadian production are higher than that of NRCan. The NEB projection of U.S. gas production is lower than either those of GRI or EIA by 5 percent in Case 1 and 10 percent in Case 2. Canadian exports fall within the range of the other outlooks.

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b *A Natural Gas Resource Assessment of the Southeast Yukon and Northwest Territories,* National Energy Board, 1996.

c *Natural Gas Potential in Canada* - A report by the Canadian Gas Potential Committee, 1997.

d *Ultimate Potential of the Supply of Natural Gas in Alberta, Report 92A,* Alberta Energy and Utilities Board, 1992.

e *The Potential for Natural Gas in the United States,* National Petroleum Council, 1992.

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g *Probabilistic Estimates of Hydrocarbon Volumes in the Mackenzie Delta and Beaufort Sea Discoveries,* National Energy Board, 1998.

h *National Assessment of the United States Oil and Gas Resources,* United States Geological Survey, 1995.

i *An Assessment of the Undiscovered Hydrocarbon Potential of the Nation's Outer Continental Shelf,* Minerals Management Service, 1995.

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k Proceedings from the 1999 CERI North American Gas Conference, March 1999.

CHAPTER 6

Natural Gas Liquids

6.1 INTRODUCTION

Natural Gas Liquids (NGL) include ethane, propane, butanes (isobutane and normal butane) and pentanes plus. This chapter examines the supply, demand and energy balances for each of these products, except pentanes plus which are included in *Chapter 7: Crude Oil*.

6.2 OVERVIEW OF THE NGL TRANSPORTATION SYSTEM AND PRODUCTION

6.2.1 Major Pipeline Systems

NGLs are currently shipped by two major pipelines to eastern Canadian and export markets. The Enbridge pipeline ships crude oil, natural gas liquids and refined petroleum products. The Cochin system transports high vapour pressure specification NGL products, ethylene and NGL mix. In 2000, the Alliance pipeline, from northeast B.C. to Chicago, will have the capability to ship approximately 15 000 cubic metres per day (m^3/d) of indigenous NGL mix in a dense phase. The NGL mix will be extracted and fractionated into specification products in the Chicago area.

In southern Saskatchewan and Manitoba, the Petroleum Transmission Company pipeline transports specification propane and butanes from a straddle plant at Empress to various locations as far east as Winnipeg. In addition, propane and heavier liquids are carried on the Enbridge Westspur and Dome Kerrobert pipelines. In Alberta and Saskatchewan, a network of pipelines, such as Peace Pipe Line, allows the movement of most NGL products from gas plants to fractionation facilities.

Specification ethane is collected by the Alberta Ethane Gathering System from straddle plants and field plants. This system is currently being expanded to meet the requirements of an ethylene plant expansion in Joffre. More detail of the NGL pipeline systems was provided in the 1994 report.[a]

Canada's main NGL export market is the United States Great Lakes area. Both Enbridge and Cochin pipelines pass through this area of the United States en route to Ontario. Canadian NGL is able to compete with both offshore and U.S. domestic products in this market area and beyond by using connecting U.S. pipelines such as the Williams pipeline system. Further, NGL mix is transported to Sarnia for fractionation and sale in nearby Canadian and eastern U.S. markets.

6.2.2 Extraction and Processing Facilities

There are over 650 natural gas plants in western Canada. The design, size and complexity of these plants depend on the composition and volume of gas being processed. After the gas has been processed in the field, it still contains most of its ethane and some heavier liquids, principally propane and butane, so that its heating value is normally above the minimum required by gas purchasers. Large straddle plants extract ethane and heavier liquids from the gas stream. These plants, six at Empress and two at Cochrane, reprocess most of the gas in the NOVA and Foothills pipeline systems. There is one smaller plant located near Edmonton to reprocess gas that is subsequently distributed locally. At Taylor, B.C., there is a straddle plant on the Westcoast system that serves markets in British Columbia and outside the province.

Approximately 49 percent of NGL is produced as ethane and heavier liquids or propane and heavier liquids. Most of this mix is transported by pipeline to de-ethanization and fractionation facilities where it is split into specification products. Fractionation facilities are located at Fort Saskatchewan, Alberta; Superior, Wisconsin; Rapid River, Michigan; Marysville, Michigan and Sarnia, Ontario.

About 84 percent of Canadian gas plant NGL supply is extracted in Alberta with lesser amounts from British Columbia (12 percent), and Saskatchewan (4 percent). In addition, about 11 percent of propane and butanes are produced from the refining of crude oil.

With the start of gas production on the Scotian Shelf, NGL will be extracted at a new plant to be constructed at Point Tupper, Nova Scotia.

6.2.3 NGL Supply

The projections of NGL gas plant supply are based on corresponding projections of natural gas production. The assumptions relating to the supply of gas within the Low Cost Supply Case (Case 1) and the Current Supply Trends Case (Case 2) are discussed in *Chapter 5: Natural Gas*. NGL production from the Scotian Shelf is expected to commence in 2001 while NGL supplies from the Mackenzie Delta are not expected until much later in the study period and only in Case 2. NGL production associated with Hibernia or other oil fields off the east coast of Canada is not included as it is expected that most of the liquids will remain in the crude oil stream.

The NGL supply projections were determined provincially, based on gas flows and current yields from conventional gas. It was assumed that unconventional gas (coal bed methane) does not contain any recoverable liquids.

A separate projection of NGL production from the Empress and Cochrane mainline straddle plants was prepared using data on the respective pipeline flows. It is assumed that straddle plants will be either constructed, expanded or have improved efficiencies to increase recoveries and process any additional gas. Some of these expansions and plans for new plants are already underway (i.e., Amoco V [31 million m³/d] and Wolcott [14 million m³/d]).

6.3 NGL SUPPLY, DEMAND AND POTENTIAL EXPORTS

Table 6.1 provides an overview of the supply for ethane, propane and butanes. Details of NGL supply and demand are provided in Appendix 6: Natural Gas Liquids.

6.3.1 Ethane

In Case 1, ethane supply is projected to increase from the current level of 32 900 m³/d to 61 000 m³/d in 2014 and then fall to 50 000 m³/d by 2025. In Case 2, the supply of ethane is projected to increase to a peak of 57 000 m³/d by 2011 and then to decline to 24 000 m³/d by 2025.

Eighty percent of ethane demand consists of feedstock requirements for the production of ethylene. Most of this demand is required for the facilities located at Joffre and Fort Saskatchewan. The ethylene facility at Fort Saskatchewan was expanded in 1998, and the construction of a new 2.8 billion pound per year cracker at Joffre is expected to be on-stream by the third quarter of 2000. In addition, a new 1.5 billion pound per year petrochemical cracker in Alberta is included in Case 1, which is projected to be on-stream by 2004. Alternatively, this capacity increase could be provided by expansions at the existing plants. In both cases, a petrochemical facility is included in Nova Scotia (0.7 billion pound per year cracker in 2001 and expanding to 1.5 billion pounds per year in 2011) which will be supplied by Scotian Shelf gas.

In Case 1, demand is expected to increase from 31 000 m³/d and peak at 55 000 m³/d in 2005; it then declines to 45 000 m³/d in 2019, after which it remains flat (Figure 6.1). In Case 2, petrochemical demand is expected to reach 49 000 m³/d in 2001 and then decrease to 38 000 m³/d in 2017, after which it remains flat. In both cases, if an ethane shortfall is perceived, an older petrochemical plant could be retired. As well, it is possible that some exported ethane could remain in Alberta to meet that demand.

6.3.2 Propane

Propane supply from both gas plants and refineries in Case 1 is expected to increase from the 1997 level of 34 000 m³/d to 51 000 m³/d in 2013 and then decline to

Table 6.1
Supply of Natural Gas liquids
(thousands of cubic metres per day)

		2010		2025	
	1997	Case 1	Case 2	Case 1	Case 2
Gas Plants					
Ethane	32.9	57.9	55.3	50.6	23.7
Propane	29.9	43.4	38.2	31.4	10.6
Butanes	15.6	22.0	19.3	15.8	5.3
Refineries (net)					
Propane	3.9	4.9	4.2	5.9	4.2
Butanes	1.8	2.3	2.0	2.8	2.1
Total					
Ethane	32.9	57.9	55.3	50.6	23.7
Propane	33.8	48.3	42.4	37.3	14.8
Butanes	17.4	24.3	21.3	18.6	7.4

37 000 m³/d by 2025 (Figure 6.2). In Case 2, propane supply peaks at 42 000 m³/d in 2008 and falls to 15 000 m³/d by 2025.

Domestic propane demand is expected to grow moderately in both cases, leaving a large volume for the export market. There is sufficient excess propane for a petrochemical facility to be built based on propane feedstock; however, this would require further expansions to manufacture finished products which may prove uneconomic.

6.3.3 Butanes

The supply of butanes, from gas plants and refineries in Case 1, is projected to increase from the current level of 17 000 m³/d to 25 000 m³/d in 2013 and then declines to 19 000 m³/d in 2025 (Figure 6.3). In Case 2, butanes supply peaks at 21 000 m³/d in 2008 and then decreases to 7 000 m³/d in 2025.

Sixty percent of butanes are used as a feedstock in the blending of gasoline. Butanes are also used for other refinery processes. Refinery requirements are expected to peak in 2005 at 8 000 m³/d when it is assumed that additional reductions in vapour pressure limits will be introduced, which will reduce demand.

Butanes are also used in the petrochemical industry as a feedstock in the production of methyl tertiary butyl ether (MTBE), a gasoline blending component; lesser amounts are used to produce olefins and acetic acid. MTBE, which is currently produced in Alberta and exported to California, will likely be phased out by the year 2002. However, it has been assumed that any loss of MTBE exports will be replaced by alkylate demand,

Figure 6.2
Propane Supply and Demand

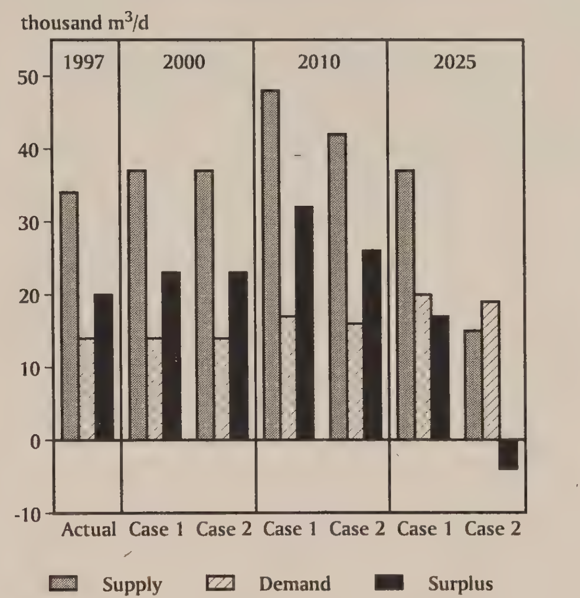


Figure 6.1
Ethane Supply and Demand

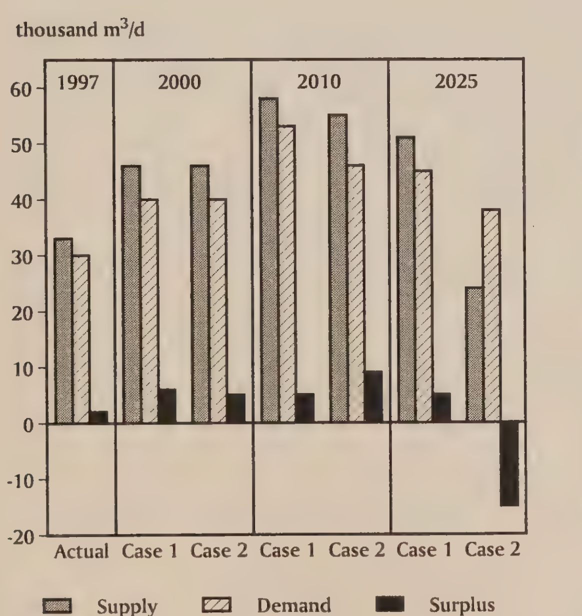
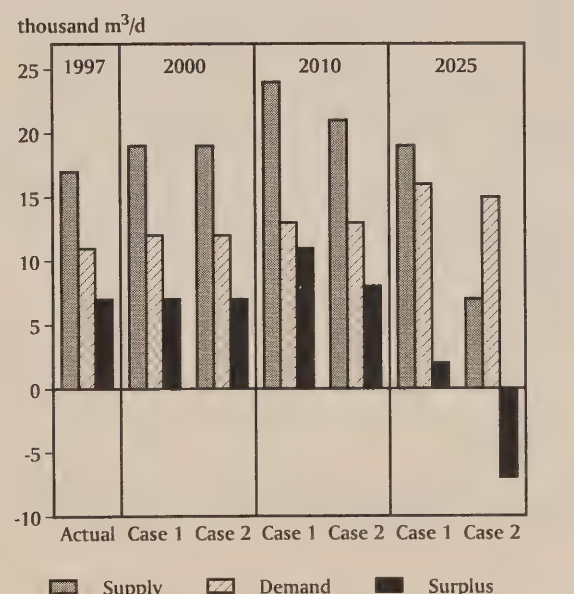


Figure 6.3
Butanes Supply and Demand



an alternate gasoline blending component, which also requires butanes.

Butanes will continue to be exported well into the projection period, but towards 2025 in Case 2, there may be a small shortfall.

REFERENCES

a *Canadian Energy Supply and Demand 1993 - 2010, Technical Report,* National Energy Board, 1994.

CHAPTER 7

Crude Oil and Equivalent

7.1 INTRODUCTION

The Board's analysis of crude oil and equivalent supply is based on estimates of resources, supply costs and productive capacity for Canada. This analysis was performed by region and by crude oil type. The balancing of domestic refinery feedstock requirements, domestic supply, imports and exports is also an important part of the analysis.[1]

The analysis is divided into two major components: conventional crude oil, which includes conventional light and conventional heavy crude oil in the Western Canada Sedimentary Basin (WCSB), and light crude oil in the Frontier and East Coast regions; and unconventional crude oil, which is comprised of Alberta's oil sands surface-mining and *in situ* projects.

The Board's resources estimates are based on the latest available data published by the Geological Survey of Canada (GSC), the provincial energy departments, the Offshore Petroleum Boards for the east coast, and its own studies.

The methodology used to estimate supply costs varies by crude type and region. For conventional crude oil in the WCSB, cash flow analysis, analysis of pool size distribution data, technical screening of resources, and trend analysis were used to prepare the projection. In-house models, using typical well profiles, were developed to estimate productive capacity and well completions. This approach is similar to that for natural gas.

For the Frontier region, the east coast and the oil sands projects, the supply cost estimates were largely based on project-specific data. These supply projections are based primarily on producers' development plans for announced projects and on information received during the consultation process. In addition, a cash-flow model was used as a comparative tool in support of the supply projections.

Projections for two cases were developed: the Low Cost Supply Case (Case 1); and the Current Supply Trends Case (Case 2). Both cases assume a constant crude oil price of US$(1997)18 per barrel for WTI at Cushing.

Supply projections for two oil price sensitivities, at US$14 and US$22 per barrel, were also undertaken. The impact on oil supply of lower oil prices ($14 Sensitivity) was developed from Case 2, while the impact of higher prices ($22 Sensitivity) was developed from Case 1. In these sensitivities, the oil price is the only variable changed. The supply projections are developed for each crude type, unconstrained by demand.

7.2 RESERVES AND RESOURCES

Table 7.1 shows the estimates of remaining established reserves, discovered and undiscovered recoverable resources, by region and crude oil category, at year-end 1997. The crude oil resources encompass all of the in-place volumes of both conventional and unconventional crude oil. The estimates of ultimate recoverable resources are broadly divided into discovered and undiscovered resources. The locations of major Canadian crude oil supply sources are depicted in Figure 7.1.

7.2.1 Resources - Conventional Crude Oil

Conventional crude oil resources are estimated to be 34 billion cubic metres (m^3) of original oil-in-place, of which only about 9.2 billion m^3 (27 percent) is estimated to be ultimately recoverable. Of this, some 7.9 billion m^3 is categorized as light crude oil and 1.3 billion m^3 as heavy crude oil. For light crude oil, 3.6 billion m^3 are estimated to exist in the WCSB and 4.3 billion m^3 in other basins (northern Canada, Ontario and offshore areas). All of the recoverable heavy crude oil is located in the WCSB. For the purposes of this study, conventional crude oil resources are characterized as light or heavy, primarily based on oil density and viscosity; however, ultimate market utilization is also considered in the classification. The Board's crude oil classifications are those of the provincial agencies, except that Alberta's light and medium grade crude oils have been

1 Detailed results are available in *Appendix 7: Crude Oil*

grouped as light, and Saskatchewan's medium and heavy crude oils have been grouped as heavy.

Western Canada Sedimentary Basin

For conventional light oil, some 3.0 billion m^3 (82 percent) of the estimated ultimate recoverable resources have been discovered, 0.7 billion m^3 (23 percent) remain in the established reserves and the future improved recovery categories. For conventional heavy oil, some 1.1 billion m^3 (82 percent) of the estimated ultimate recoverable resources have been discovered, and of these discovered resources, 0.5 billion m^3 (50 percent) remain in the established reserves and the future improved recovery categories. These values indicate the relative state of maturity of oil exploration within the WCSB.

The Board's estimates of undiscovered recoverable resources for light and heavy crude oil are based on estimates for oil-in-place from the GSC.[a] These estimates were adjusted to account for discoveries made since 1995 and to reflect reserves appreciation. Also, there have been some recent discoveries made in zones not evaluated by the GSC, which have been added to the resources, based on comments received during the consultations.

Table 7.1
Crude Oil and Bitumen Resources at Year-end 1997
(million cubic metres)

	Discovered Recoverable Resources						
	Cumulative Production	Remaining Established Reserves	Future Improved Recovery[1]	Total	Undiscovered Recoverable Resources	Ultimate Recoverable Resources	Original Oil In Place
Conventional Crude Oil	**2 792**	**666**	**1 096**	**4 555**	**4 623**	**9 177**	**34 388**
Subtotal - Light	**2 255**	**459**	**784**	**3 499**	**4 394**	**7 892**	**27 813**
WCSB - Subtotal	*2 211*	*338*	*408*	*2 957*	666	*3 623*	*11 383*
British Columbia	87	23	18	129	55	184	512
Alberta	1 910	259	267	2 436	570	3 007	9 199
Saskatchewan	181	51	121	353	34	387	1 437
Manitoba	32	5	2	39	7	46	235
Ontario	12	2	0	14	0	14	62
Frontier - Subtotal	*32*	*119*	*376*	*528*	*3 727*	*4 255*	*16 368*
Nova Scotia Offshore	6	2	3	11	83	94	493
Newfoundland Grand Banks	0	106	145	251	498	749	3 365
Mainland NWT & Yukon	26	11	2	40	55	95	315
Mackenzie Delta & Beaufort Sea	0	0	161	161	905	1 066	3 610
Arctic Islands	0	0	65	65	686	751	2 785
Other Frontier Basins[2]	0	0	0	0	1 500	1 500	5 800
Subtotal - Heavy	**536**	**208**	**312**	**1 056**	**229**	**1 285**	**6 575**
Alberta	215	68	122	405	96	501	2 406
Saskatchewan	322	140	190	651	133	784	4 169
Oil Sands	**407**	**614**	**47 979**	**49 000**	**0**	**49 000**	**400 000**
Mining Projects[3,4]	304	340	9 356	10 000	0	10 000	24 100
in situ Projects[3]	103	274	38 623	39 000	0	39 000	375 900

1 In conventional light & heavy categories, this refers to future enhanced recovery from the existing discovered pools. In frontier regions, this refers to pools currently discovered but not yet on production due to economic or technical conditions.

2 Resource estimates for prospective regions which lack confirming discoveries have been aggregated. These regions include the Georges Bank and Laurentian Sub-basin, East Newfoundland Basin and southern Grand Banks, the St. Lawrence Lowlands and Maritimes Basin, Hudson Bay, eastern Arctic offshore and the Queen Charlotte, Tofino and Georgia Basins.

3 Cumulative production and remaining established reserves estimates include only projects under active development.

4 Cumulative production figures are for the raw bitumen volumes.

The total estimate of undiscovered resources for the WCSB has been disaggregated to the provincial level by assigning the GSC estimate for each play to the provinces where the play is expected to have potential. Therefore, the provincial break-down should be used with some caution.

Table 7.2 illustrates the changes made to the ultimate recoverable resources estimates in this report compared to the 1994 report.[b] Conventional light crude oil is 11 percent higher and heavy conventional crude oil is 14 percent higher than the 1994 values.

Frontier and East Coast

Canada's frontier areas include the B.C. offshore, the central Mackenzie Valley region, the interior Yukon Territory basins, the Mackenzie Delta/ Beaufort Sea region, the Arctic Islands and the east coast offshore.

Table 7.2
Ultimate Recoverable Resources - WCSB Conventional Crude Oil
(million cubic metres)

	Light Crude Oil		Heavy Crude Oil	
	1999 Report	1994 Report	1999 Report	1994 Report
Initial Established Reserves	2 549	2 355	744	566
Discovered Resources	408	395	312	300
Undiscovered Resources	666	519	229	260
Ultimate Recoverable Resources	3 623	3 269	1 285	1 125

Figure 7.1
Crude Oil Supply Sources

In these projections, only portions of the east coast and northern Canada resources are expected to be exploited during the study period; therefore, the discussion is limited to these areas.

For the ultimate recoverable resources, the Board has adopted the GSC estimates. For each basin, these estimates are usually expressed as a range with associated probabilities of occurrence. For the purpose of aggregating resource estimates, the mean expectation was selected from the probability distribution for each assessment area.

Newfoundland Grand Banks

The estimates of undiscovered recoverable resources for Newfoundland Grand Banks are those published by the Canada - Newfoundland Offshore Petroleum Board, adjusted for volumes recognized as established reserves. The 106 million m^3 of established reserves shown in Table 7.1 is for the Hibernia field, which began production in 1997. It is expected that the Terra Nova field will be moved into this category in 2000, which will lead to an increase of the established reserves by 64 million m^3.

Scotian Shelf

The estimates of undiscovered resources for Nova Scotia are those published by the Canada - Nova Scotia Offshore Petroleum Board, adjusted for volumes recognized as established reserves. The Cohasset/Panuke field has been active since 1992 and has remaining reserves of 1.7 million m^3.

Northern Frontier

The estimates of undiscovered resources for the mainland Territories and the Mackenzie Delta - Beaufort Sea are based on the 1994 report[b] and an NEB update prepared in 1998.[c] The volumes have been adjusted to recognize the established reserves. Only the Norman Wells field in the central Mackenzie Valley is currently producing, with remaining reserves estimated at 11.3 million m^3.

7.2.2 Resources - Unconventional Crude Oil

The unconventional resources consist entirely of the bitumen contained in three large areas in northern Alberta, defined by the Alberta Energy and Utilities Board (EUB) as the Athabasca, Cold Lake and Peace River Oil Sands Areas. For the oil sands, the Board has adopted the EUB resources estimates.[d] Original bitumen in place is estimated to be 400 billion m^3, of which 49 billion m^3 (12 percent) is estimated to be ultimately recoverable. Additional undiscovered resources may exist, but these are not expected to be significant in relation to the discovered resources.

The remaining established reserves comprise only the currently active commercial and experimental projects and consist of 340 million m^3 for the oil sands mining projects and 274 million m^3 for the oil sands in situ projects.

7.3 TYPICAL WELL PROFILES

Typical well production profiles were developed for the WCSB for four types of wells: light vertical; light horizontal; heavy vertical; and heavy horizontal. The performance data for all conventional crude oil wells in the WCSB were grouped according to province, well type and year of first production, for the years 1992 to1996. This data was used to determine average or “typical” values for initial production rates, decline trends and reserves per well (Figure 7.2).

The typical well production profiles and reserves per well have been kept constant over the projection, and are the same in both cases. This data was used in the projection of supply costs, drilling completions and supply for light and heavy conventional crude oil. While the trend to finding increasingly smaller pools over time could potentially change the shape of the well profiles, it is assumed that this trend will be offset by advances in exploration and production technology.

7.4 SUPPLY COSTS AND RECOVERABLE RESOURCES

Supply costs are expressed as full cycle, which includes all costs associated with exploration, development and production. They include capital costs, operating costs, taxes and royalties and a six percent real rate of return to the producer. Supply costs are quoted in Canadian dollars of 1997 unless otherwise noted.

Based on the estimated supply costs, an evaluation of the discovered and undiscovered recoverable resources was carried out to determine the portion that would be economically recoverable.

7.4.1 Western Canada Sedimentary Basin

The total economically recoverable resources are estimated to be 1 086 million m³ and 986 million m³ for Case 1 and Case 2 respectively (Table 7.3).

Remaining Discovered Recoverable Resources

The remaining discovered recoverable resources category for conventional crude oil consists of remaining established reserves and future improved recovery. In both cases, it was assumed that all of the remaining established reserves will be economically recoverable. A more detailed assessment was done for the future improved recovery category.

A technical screening was conducted to estimate the volume of resources amenable to some form of improved recovery, using the criteria described in a 1997 JCPT paper.[e] For each technique of improved recovery, estimates of the costs to develop and produce the incremental resources were applied to the available resources to determine recoverable volumes. It is estimated that 540 million m³ (75 percent) of the resources in the future improved recovery category, would be economically recoverable in Case 1, compared to 440 million m³ (61 percent) in Case 2.

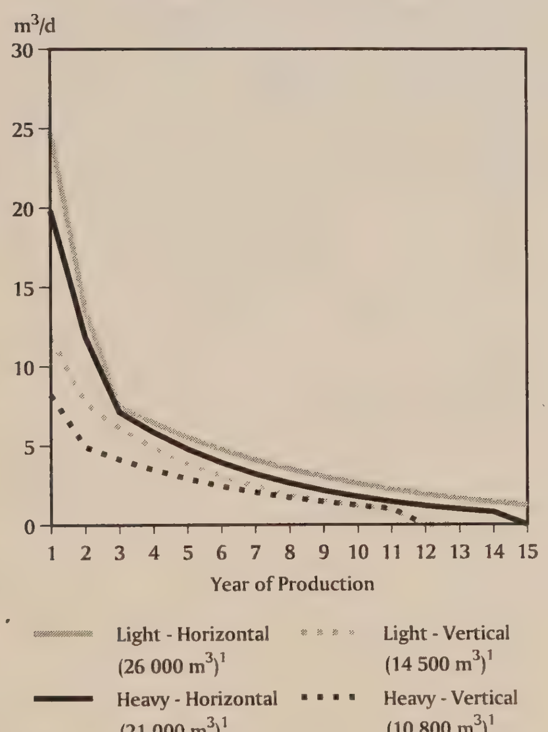
In the $14 Sensitivity, the total economically recoverable discovered resources are estimated to be 534 million m³ for conventional light crude oil and 355 million m³ for conventional heavy crude oil. Compared to Case 2, this represents a decrease of 10 percent, for each of light and heavy crude oil.

The $22 Sensitivity indicates 689 million m³ and 467 million m³ of economically recoverable discovered resources for conventional light and heavy, respectively. Compared to Case 1, this represents an increase of 7 percent for conventional light and an increase of 6 percent for conventional heavy crude oil.

Undiscovered Recoverable Resources

For the undiscovered conventional resources in the WCSB, the determination of pool size distribution was based on the latest GSC[a] estimates, which identified over 90 geological plays and seven distinct groups based on geological horizon. These resources distributions were then matched with the appropriate estimates

Figure 7.2
Typical Well Profiles - WCSB



1 indicates total recovery per well.

Table 7.3
Remaining Recoverable Conventional Resources in the WCSB
(million cubic metres)

	Case 1	Case 2	$14 Sensitivity	$22 Sensitivity
Conventional				
Crude Oil - Total	1 887	1 733	1 342	1 986
Discovered Recoverable	1 086	986	889	1 156
Remaining Established	*546*	*546*	*546*	*546*
Future Improved Recovery	*540*	*440*	*342*	*610*
Undiscovered Recoverable	801	747	453	830
Light Crude Oil - Total	1 257	1 157	834	1 315
Discovered Recoverable	644	591	534	689
Remaining Established	*338*	*338*	*338*	*338*
Future Improved Recovery	*306*	*253*	*196*	*351*
Undiscovered Recoverable	613	566	300	626
Heavy Crude Oil - Total	630	576	508	671
Discovered Recoverable	442	395	355	467
Remaining Established	*208*	*208*	*208*	*208*
Future Improved Recovery	*234*	*187*	*147*	*259*
Undiscovered Recoverable	188	181	153	204

of the costs incurred to find, develop and produce the incremental resources. The production profiles for all oil pools were estimated using a typical well production profile developed for the WCSB (see Section 7.3). An example of the results of this analysis for the Devonian play is shown in Appendix 7.

The capital and drilling costs were determined by examining historical data[f] since 1992. Estimates of operating costs were obtained from industry sources.

A supply cost curve for each geological play or basin was generated by sorting individual pools in ascending order of cost, based on the assumption that lower cost pools, typically larger ones, will be discovered first. The supply cost curves for all pools were aggregated to produce a supply cost curve for the WCSB. Figure 7.3 shows the resulting supply cost curve for the undiscovered light oil resources and Figure 7.4 shows the supply cost curve for the undiscovered conventional heavy oil resources.

In Case 1, supply costs for light crude oil rise gradually to about $20.00 per barrel, and then move sharply upward, at a point where about 92 percent of the undiscovered resources will have been found. For Case 2, the supply costs also trend gradually upward, to about $21.50 per barrel, and then rise fairly quickly when about 85 percent of the undiscovered resources will have been found. On average, the difference in supply costs between the two cases is about $1.50 per barrel.

In Case 1, supply costs for heavy crude oil rise gradually from $15 per barrel to $19 per barrel, before trending upwards, when 75 percent of the undiscovered resources will have been found. In Case 2, the supply cost is about $1.50 per barrel higher and a sharp increase in cost occurs when about 62 percent of the resources will have been found.

In Case 1, it is estimated that 801 million m³ of the undiscovered crude oil resources would be economically recoverable. In Case 2, this drops to 747 million m³. In the $14 Sensitivity, the total economically recoverable undiscovered resources are estimated to be 453 million m³. Compared to Case 2, this represents a decrease of 40 percent. For the $22 Sensitivity, the total economically recoverable resources is 830 million m³, about 4 percent higher than in Case 1.

7.4.2 Newfoundland Grand Banks

In these projections, all of the recoverable resources in the Grand Banks are expected to be in the Jeanne d'Arc Basin. The analysis of supply costs and recoverable resources for this basin uses the resources indicated in Section 7.2.1. The estimate of pool size

Figure 7.3
WCSB Supply Cost - Undiscovered Light Resources

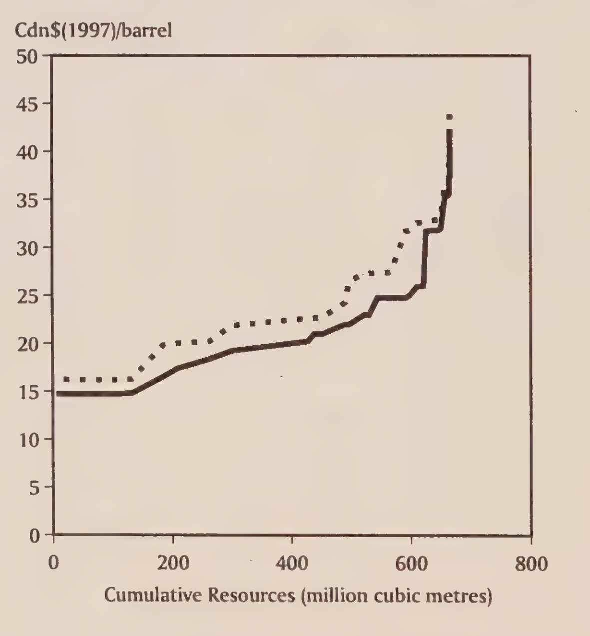
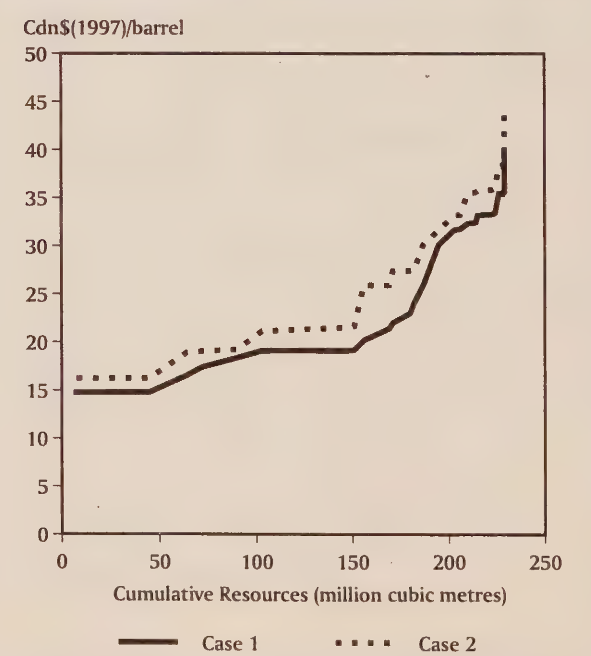


Figure 7.4
WCSB Supply Cost - Undiscovered Heavy Resources



distributions was based on the methodology described by Crovelli.[8] This analysis suggested a supply cost, at the production facility, in the range of $13 to $18 per barrel.

The supply costs for the Jeanne d'Arc Basin suggest that 609 million m³ (81 percent) and 552 million m³ (74 percent) of the 749 million m³ of ultimately recoverable resources could be economically recovered in Case 1 and Case 2, respectively.

For the $14 Sensitivity, this estimate decreases to 479 million m³, 13 percent lower than in Case 2, while in the $22 Sensitivity the estimate increases to 652 million m³, 7 percent higher than in Case 1.

7.4.3 Frontier Regions and Unconventional Crude Oil

For the Frontier regions, the oil sands *in situ* and the oil sands mining projects, supply costs are based on announced development plans for major projects, data supplied during the consultations and subsequent discussions with industry. These costs do not include transportation to market. The range of supply costs presented in Table 7.4 has been used as a guide to estimate the pace of development for these resources.

7.5 OIL WELL COMPLETIONS IN THE WCSB

The projection of successful drilling completions is based on the typical well profiles and estimates of recoverable resources. For both light and heavy crude, completion levels are higher in Case 1 than in Case 2, reflecting the higher volume of recoverable resources. Due to recent low oil prices and restricted cash flow in the industry, drilling is sharply lower in 1999, but it is expected to recover after 2000.

Successful completions for conventional light crude oil in the WCSB peak in 2003 for both cases, at 2 172 in Case 1 and 2 013 in Case 2 (Figure 7.5). In both cases, horizontal wells comprise about 17 percent of the total completions.

For heavy conventional crude oil, completions peak in 2002 for both cases, with 2 568 wells drilled in Case 1 and 2 456 in Case 2. In both cases, horizontal wells account for 33 percent of total completions over the projection period.

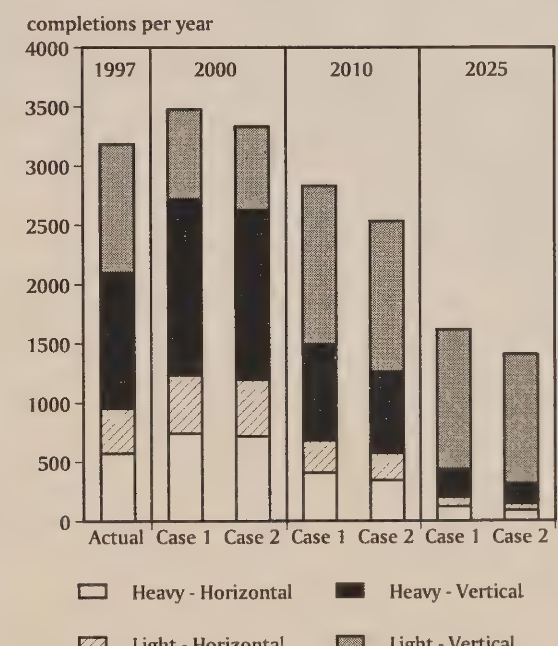
Table 7.4
Supply Costs for Frontier Regions and Unconventional Crude Oil Projects
Cdn$(1997) per barrel

	Case 1	Case 2
Frontier Regions		
Newfoundland Grand Banks	13 to 17	14 to 18
Mackenzie/Beaufort	13 to 16	14 to 17
Oil Sands - Bitumen		
in situ Primary Recovery	8 to 10	9 to 12
in situ Steam-Assisted Recovery	12 to 16	13 to 17
Oil Sands - Upgraded Crude		
Integrated Mining Plants	15 to 18	17 to 20
Stand-Alone Upgraders	18 to 22	20 to 24

7.6 CRUDE OIL SUPPLY

The projections have two components: supply from remaining established reserves; and supply from reserves additions. For the remaining established reserves, a constant reserves to production ratio is assumed in both cases. Supply from reserves additions

Figure 7.5
WCSB Oil Well completions[1]



1 excluding bitumen wells

is derived from undiscovered resources and future improved recovery.

7.6.1 Western Canada Sedimentary Basin

The supply projections indicate that the WCSB conventional crude oil resources will be substantially depleted by 2025 and producing at low rates, with the effect more pronounced in heavy than in light oil. Despite the increase in the estimates of heavy oil resources, the supply of heavy oil will be constrained by resources after 2010.

Conventional Light Crude Oil

Since 1994, light crude oil production has been trending upward in British Columbia and Saskatchewan, has been relatively constant in Manitoba, and has been declining by about 4 percent per year in Alberta. Because Alberta accounts for 75 percent of total production, the combined effect for the WCSB has been a decline of 3 percent per year. These trends were used as a guide to develop the supply projections.

In both cases, the decline in production from established reserves is about 13 percent per year. The supply contribution from reserves additions increases until 2009 to a maximum of about 62 000 m³/d in Case 1, and 57 000 m³/d in Case 2. After 2009, the total supply is expected to show a relatively steady decline, with Case 1 declining at 3.9 percent and Case 2 declining at 4.2 percent per year (Figure 7.6).

Compared to Case 2, supply in the $14 Sensitivity is lower by 18 700 m³/d in 2006. This difference decreases to 14 600 m³/d by 2025. Compared to Case 1, supply in the $22 Sensitivity is greater by 7 800 m³/d in 2006. This difference declines to 2 800 m³/d by 2025.

Conventional Heavy Crude Oil

In the past decade, conventional heavy oil production has increased by about seven percent per year, in both Alberta and Saskatchewan. Contrary to this trend, production declined in 1998 because of a significant drop in drilling activity due to low oil prices. Although the supply projections for both cases show some recovery by the year 2000, the economic assumptions do not support a return to the robust growth of the pre-1998 period (Figure 7.7).

For supply from established reserves, the initial decline is about 16 percent per year, but flattens to about 12 percent per year. The supply contribution from reserves additions increases over time to a maximum of about 61 000 m³/d in 2007 in Case 1, and 58 000 m³/d, in Case 2, also in 2007. Total supply declines by about 9 percent per year in Case 1 and by about 10 percent per year in Case 2.

In the $14 Sensitivity, the supply is 7 200 m³/d lower than in Case 2 in 2012. This difference decreases to 3 900 m³/d by 2025. In the $22 Sensitivity, the supply is greater than in Case 1 by 7 800 m³/d in 2009. This difference narrows to 2 800 m³/d by 2025.

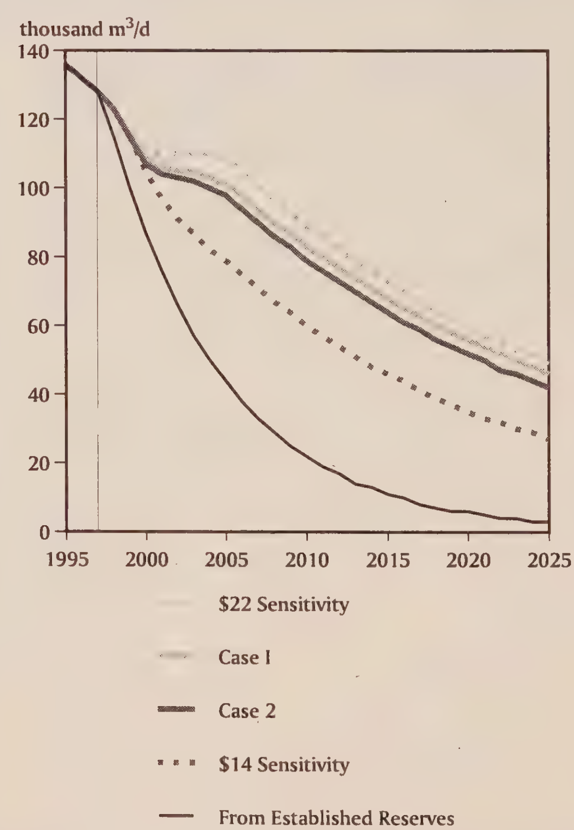
7.6.2 Eastern Canada

The crude oil supply projections for Eastern Canada include production from the currently producing areas of: Ontario (1 600 m³/d); Cohasset/Panuke (1 500 m³/d); and Hibernia (20 000 m³/d). In the future, Newfoundland is expected to account for almost all of the production from this region (Figure 7.8).

Newfoundland Grand Banks

The supply projections for Newfoundland are based on the estimates of recoverable resources discussed in

Figure 7.6
WCSB Conventional Light Crude Oil Production



Section 7.4.2 and on submissions received as part of the Round 2 Consultations.

The Hibernia and Terra Nova fields are treated similarly in both cases. Hibernia production peaks at 24 000 m³/d in 2001, while Terra Nova is expected to come on stream by 2001 and peaks at 20 000 m³/d by 2002. In Case 1, the Hebron and Whiterose fields are assumed to start production in 2004 and 2005, respectively. In Case 2, Hebron comes on stream in 2004, but Whiterose is delayed until 2006.

Total production peaks in 2007 at 70 000 m³/d in Case 1 and 60 000 m³/d in Case 2, and remains at that level until 2015. It is anticipated that these levels will be achieved through improved recovery from discovered fields, the exploitation of sattelite fields, and production from undiscovered fields. Beyond 2015, the declining production in both cases reflects the constraint of the estimated recoverable resources.

Maintaining production at peak levels beyond 2015 would require the recognition of additional resources. Because this region is in the early stages of exploration and development, estimates of ultimate resources are still relatively uncertain, and a corresponding level of uncertainty should be applied to the supply projections.

In the $14 Sensitivity, production peaks at 50 000 m³/d, which is 17 percent lower than in Case 2; however, the rate of decline after 2015 is slightly smaller. In the $22 sensitivity, production peaks at 80 000 m³/d, which is 14 percent higher than in Case 1; however, the rate of decline is slightly greater after 2015.

Scotian Shelf and Ontario

The Cohasset/Panuke field was put on stream in 1992 and its production is expected to decline to its economic limit by 2000. For Nova Scotia and Ontario, no supply beyond the established reserves has been included in the projections.

7.6.3 Northern Frontier

Norman Wells is the only field currently producing in the north. The current production level of 4 300 m³/d is expected to decline to 2 100 m³/d by 2025.

Figure 7.7
WCSB Conventional Heavy Crude Oil Production

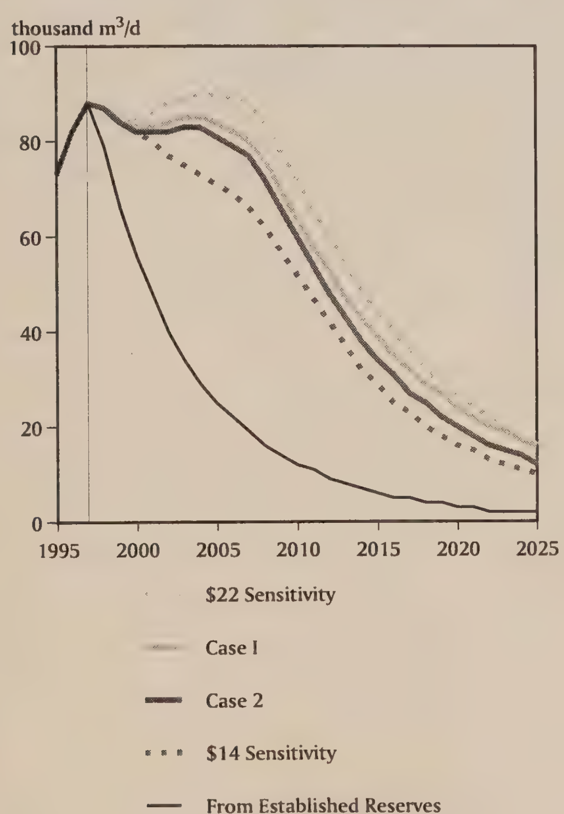
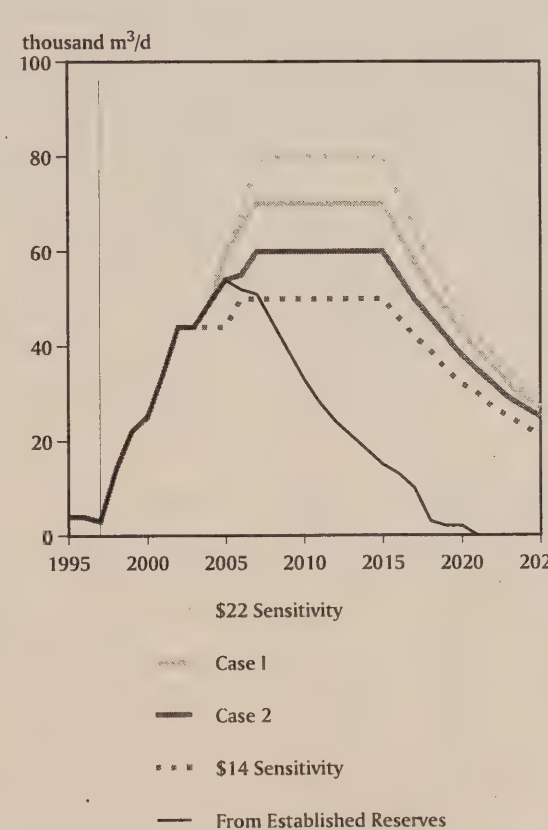


Figure 7.8
Eastern Canada Crude Oil Production



Despite a discovered resources of 161 million m^3 for the Mackenzie Delta - Beaufort Sea region, production is not expected in neither Case 1 nor Case 2, due to the high costs of transporting the crude oil to market ($12 to $16 per barrel). However, in the $22 Sensitivity, production from this region is expected to begin in 2010 and reach 25 000 m^3/d by 2012.

7.7 OIL SANDS

To avoid confusion with other oil products, the Board has adopted the terminology of "Oil Sands - Upgraded Crude" to refer to the production from oil sands mining projects and of "Oil Sands - Bitumen" to refer to production from oil sands *in situ* projects. Upgraded Crude was formerly called Synthetic Crude.

Production from oil sands projects has been growing steadily and is an increasingly important component of total Canadian crude oil production. While production levels from these projects have steadily increased through various productivity improvements, the industry is now entering a period of accelerated growth. Past experience, combined with intensive research and development programs, has resulted in new drilling, extraction, mining, upgrading and transportation methods that have substantially lowered the costs of production. As well, the fiscal environment has been improved by recent changes in the oil sands royalty structure in Alberta and by changes in the federal income tax regulations for mining. An additional incentive is provided by rental fees that are now inversely tied to the pace of development of oil sands leases.

Syncrude Canada Ltd. (Syncrude) and Suncor Energy Inc. (Suncor) have halved their operating costs at their integrated mining/upgrading facilities in the last decade. The projected operating cost for new expansion projects is about $10 per barrel.

With respect to *in situ* bitumen, long standing players such as Imperial Oil Ltd. (Imperial), BP-Amoco plc (BP-Amoco) and Shell Canada Ltd. (Shell) have acquired a wealth of experience in cyclic-steam stimulation and are planning to expand their projects. Numerous new techniques, primarily thermal methods, when combined with horizontal drilling, are very promising. The application of the progressive cavity pump and innovative sand handling procedures has led to successful primary production in certain oil sands areas that contain a lighter bitumen, such as Pelican Lake.

The development of processes to conduct partial upgrading at the field or in the reservoir and the development of small-scale or "modular" upgraders are promising technologies that could lead to a move away from large, expensive integrated mining/upgrading facilities.

7.7.1 Oil Sands - Upgraded Crude

To date, there are only two large scale integrated mining/upgrading projects, respectively operated by Syncrude and Suncor, in the Athabasca Oil Sands Area of Alberta.

As part of its "Syncrude 21" project, Syncrude plans to expand production through two stages of capacity increases at its upgrading facilities. When combined with the development of its North and Aurora Mines, upgraded crude production is expected to reach 67 000 m^3/d by 2007, double the current levels.

Suncor's Project Millennium is designed to increase production from about 13 000 m^3/d in 1997, to 33 000 m^3/d by 2002. The project includes the Steepbank Mine, which is already in operation, and the twinning of existing extraction and upgrading facilities.

Several companies have announced proposals to develop new integrated mining/upgrading projects. Shell plans a 24 000 m^3/d project at Muskeg River (Lease 13), with the mined bitumen to be transported via pipeline to a new upgrader, proposed to be integrated with its Scotford refinery in Edmonton. Other projects have also been announced by Mobil Oil Canada Ltd. and by Koch Canada Ltd.

The supply projections in Case 1 include the expansion projects of Syncrude and Suncor, with Suncor reaching full production by 2003 and Syncrude by 2008. In addition, the Shell Muskeg River project is assumed to start production in 2003. Case 1 also includes an unspecified project with a capacity of 15 000 m^3/d, starting in 2007. As well, other expansions are assumed to provide an additional 5 000 m^3/d in 2015 increasing to 20 000 m^3/d by 2025. By the end of the projection period, production is estimated to reach 170 000 m^3/d, nearly four times the 1997 levels (Figure 7.9).

In Case 2, the same expansion projects for Syncrude and Suncor are included. However, there is only one

additional unspecified project brought on stream in 2010, with a capacity of 15 000 m³/d. In the later stages of the Case 2 projection, other expansions totaling 8 000 m³/d are assumed, and production reaches 135 000 m³/d by 2025.

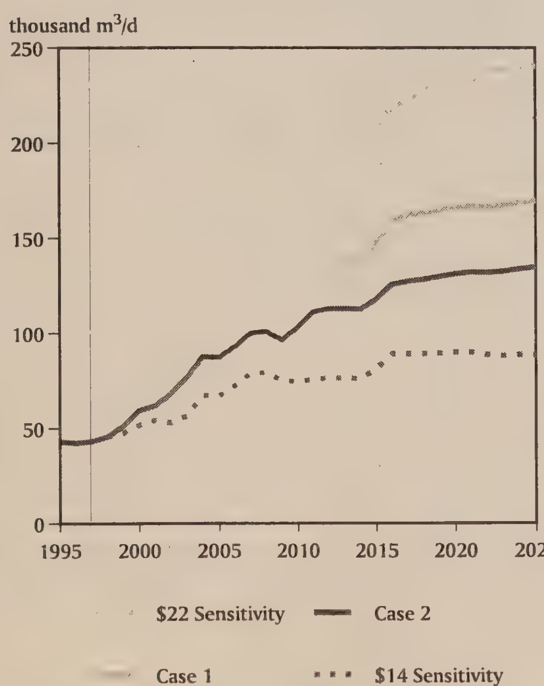
In the $14 Sensitivity, only the Suncor and Syncrude expansions proceed, with the completion date of the Syncrude expansion delayed until 2010. The production rate in 2025 is 89 000 m³/d, which is 35 percent lower than in Case 2.

In the $22 sensitivity, all five of the currently announced projects proceed. As well, an additional 56 000 m³/d is brought on between 2008 and 2025, allocated to undefined projects that could include project expansion, new large scale projects or smaller scale projects. Production reaches 241 000 m³/d in 2025, which is 40 percent higher than in Case 1.

7.7.2 Oil Sands - Bitumen

Since 1993, *in situ* bitumen production has roughly doubled, reaching a level of 38 000 m³/d in 1997. Projects operated by Imperial and BP-Amoco in the Cold Lake/Primrose area account for most of the bitumen production to date, but there has also been significant production from the Lindbergh and Peace River areas.

Figure 7.9
Oil Sands - Upgraded Crude Supply



Since 1996, over 40 new *in situ* bitumen projects or expansion phases have been proposed, but most of these plans were put on hold due to the recent slump in oil prices. While there is a wide range of estimated supply costs for bitumen projects, the assumption of US$18 per barrel (WTI) looks relatively attractive for established producers. It is assumed that the existing major projects will remain viable and expand. It is also assumed that some new projects will proceed, with the pace of development accelerating over time as supply costs decline. In both cases, the price of natural gas increases over time, which leads to rising costs of steam generation and affects the viability of steam stimulation projects. In the supply outlook, some projects occur later in Case 2 than in Case 1, reflecting the slower pace of technological advance and higher gas prices.

Production in the two cases does not diverge appreciably until after 2003, because the supply costs are similar until that time. By 2025, production rates are about 116 000 m³/d and 95 000 m³/d for Case 1 and Case 2, respectively (Figure 7.10).

In the $14 Sensitivity, bitumen production is sharply reduced, dropping to 40 000 m³/d by 2002 before gradually recovering to 65 000 m³/d by 2025, about 32 percent lower than in Case 2. In the $22 Sensitivity, the production of bitumen rises markedly, reaching 187 000 m³/d by 2025, which is 61 percent higher than in Case 1.

The above projections include primary bitumen production from the oil sands regions. This production increases from about 2 500 m³/d in 1997 to about 10 000 m³/d by 2005 in Case 1 and remains flat after that. In Case 2, the level is similar, but the maximum production is not reached until 2007.

7.8 LIGHT/HEAVY OIL PRICE DIFFERENTIAL

Light crudes generally command higher prices than heavy crudes and bitumen, reflecting their relative value to refiners. The refiner's choice of feedstock mix is based on the relative market values of products obtained from light oil versus heavy oil processed at coking refineries. This "coking differential" determines the minimum light/heavy price differential required by refiners. The posted prices for Light Par at Edmonton

and Bow River Heavy Blend at Hardisty were used to calculate the light/heavy differential.

Between 1988 and 1998, the differential has fluctuated between \$3 and \$9 per barrel, averaging \$5 per barrel. In general, when heavy crude supply is tight, the differential narrows; when it is more abundant, the differential widens. The amount of conversion capacity for heavy crudes also plays an important role. The slump in crude oil prices in 1997 and 1998 resulted in decreased heavy oil production in the WCSB, which led to a situation where the demand for Canadian heavy crude in the U.S. Midwest region outpaced supply. As a consequence, the differential dipped to about \$2 per barrel early in 1999.

In both cases, it is assumed that the differential will gradually increase to \$5 per barrel by 2002 and remain at that level, which is consistent with the long-term average. It is likely that the differential will cycle between minimum and maximum values, but no attempt was made to define the timing of these cycles.

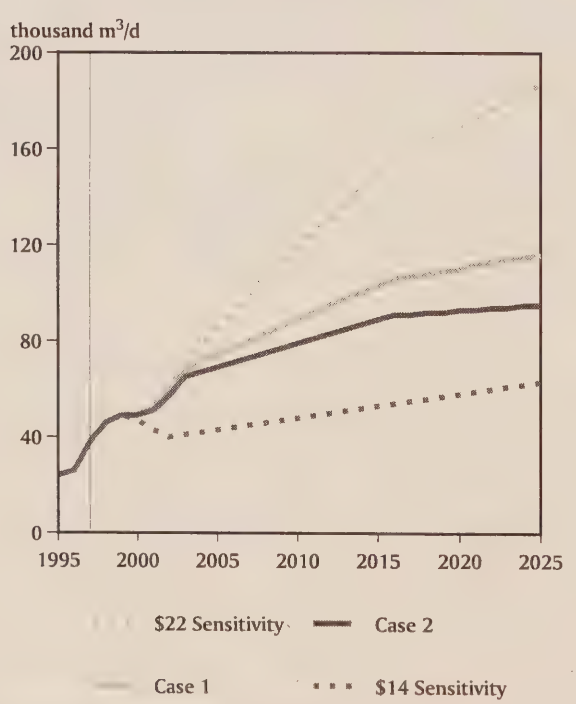
7.9 REGIONAL UPGRADING

The projected supply of heavy oil, bitumen and upgraded crude oil is dependent on the installation of additional upgrading capacity, either in Canada or in U.S. markets. This upgrading can take place in many types of facilities, such as: integrated mining/upgrading plants; stand-alone regional upgraders; upgraders associated with existing refineries; and smaller scale field upgraders. Some producers are also considering the production of partially upgraded crudes which would require less diluent, as well as crudes tailored specifically to refinery requirements. In general, the upgrading capacity will be added if the light/heavy differential justifies the investment. Also, as the supply of pentanes plus for diluent tightens, its price will increase, which will provide an additional incentive for upgrading.

There are many promising research projects being carried out on new and enhanced methods of refining bitumen and heavy crude, as well as on partial upgrading at the field level. The potential exists for significant technological advances that could significantly lower the cost of upgrading.

In both cases, it is assumed that the proposed expansion of the Husky Lloydminster upgrader will come on stream in 2001, increasing its capacity from 10 300 m³/d to 23 200 m³/d. Additional unspecified upgrading capacity of 13 000 m³/d is brought on stream in 2008 for Case 1 and in 2015 for Case 2.

Figure 7.10
Oil Sands - Bitumen Supply



7.10 PENTANES PLUS SUPPLY AND DILUENT REQUIREMENT

Although some pentanes plus are derived from field condensate, the bulk of the supply is derived from the processing of natural gas. Therefore, the projection of pentanes plus supply is directly tied to that of natural gas (see Chapter 5). Pentanes plus are included in the oil chapter because they are used primarily as a diluent to blend with heavy oil and bitumen, and as a direct refinery feedstock.

In Case 1, the supply of pentanes plus is projected to increase from the current level of about 26 000 m³/d to 36 300 m³/d in 2013, it then declines to 23 000 m³/d in 2025. In Case 2, supply is projected to rise to 31 000 m³/d in 2011, it then decreases to 7 000 m³/d by 2025. These volumes do not include production from Newfoundland offshore oil projects, which is expected to remain in the crude oil stream.

In the $14 Sensitivity, the pentanes plus supply is 9 percent less than in Case 2, while in the $22 Sensitivity, it is 3 percent greater.

Diluent Requirement

The largest use of pentanes plus is for diluent in the blending of heavy crude oil and bitumen to facilitate its transportation to market by pipeline. Typically, raw bitumen requires the addition of approximately 40 percent of diluent, while conventional heavy crude requires about 7 percent. In 1997, there was a relative shortage of pentanes plus for use as diluent and several steps were taken to alleviate the situation. A new viscosity standard was implemented on the Enbridge pipeline system early in 1999, which reduced the diluent requirement by about 10 percent. As well, a condensate price equalization program was developed to encourage the use of light crude oil as diluent.

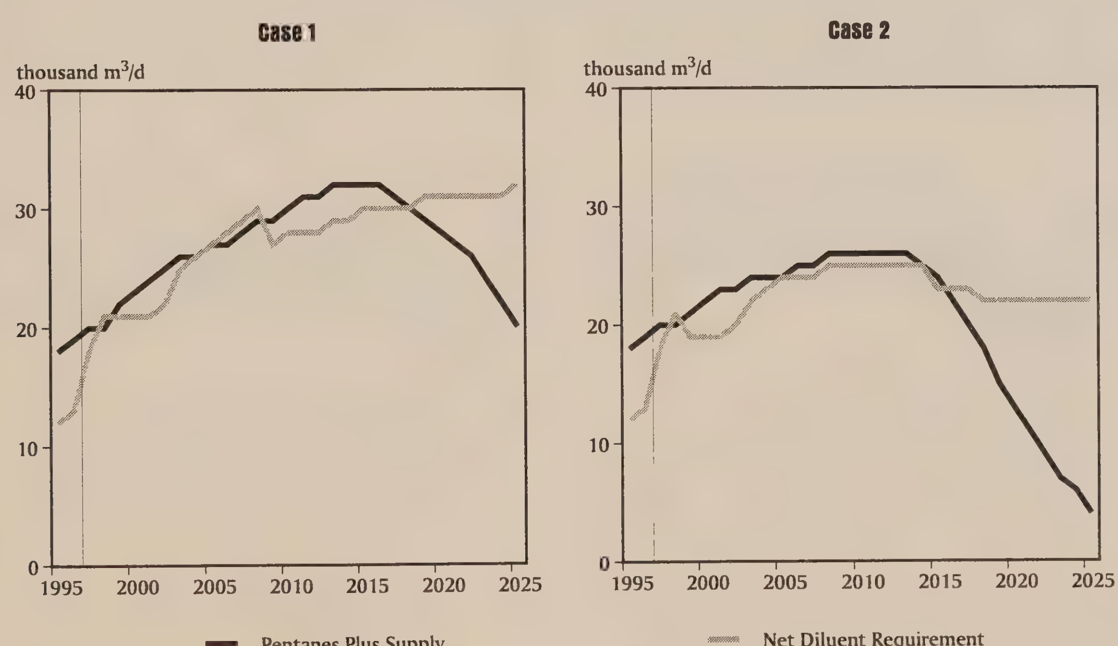
It is estimated that about 4 000 m^3/d of pentanes plus will not be available for use as diluent. This includes the volumes that are used in miscible flooding for improved oil recovery projects, as refinery feedstock, and those that remain in the light crude oil stream.

Two important determinants of the demand for diluent are the pace of development of bitumen projects and the amount of upgrading installed. New oil sands mining developments are assumed to include upgrading capacity; hence, they require no net diluent. However, *in situ* bitumen projects are assumed to include only partial or no upgrading; hence, they will require significant amounts of diluent. Figure 7.11 provides an indication of the balance between pentanes plus supply and diluent requirement for the two cases. A substantial shortfall occurs by 2018 in Case 1 and 2016 in Case 2. By 2025, a shortfall of about 11 000 m^3/d is shown for Case 1, compared to about 18 000 m^3/d in Case 2. Although more heavy blend is produced in Case 1 than in Case 2, additional upgrading comes on sooner, which reduces net diluent requirements.

In the $14 Sensitivity, the diluent requirement is about 12 000 m^3/d less than in Case 2, by 2025. As a result, the potential shortfall for use as diluent does not occur until 2022. In the $22 Sensitivity, the diluent requirement is about 22 000 m^3/d greater than in Case 1, by 2025. The potential shortfall first occurs in 2006 and reaches 33 000 m^3/d by 2025.

The potential shortfall could be alleviated by adding local upgrading capacity. Alternatively, some of the shortfall could be made up by some other diluent, such as light crude oil or light refined products, such as naphtha. Nevertheless, the potential shortage is not

Figure 7.11
Pentanes Plus Supply vs. Net Diluent Requirement



expected to constrain the development of heavy oil or oil sands projects.

7.11 NET AVAILABLE SUPPLY - CRUDE OIL AND EQUIVALENT

The net available crude oil production represents the total of conventional light crude, upgraded crude, pentanes plus and blended heavy crude that is available to refiners, after local feedstock and diluent requirements have been met (Figure 7.12). It is assumed that none of the light crude will be used as diluent. The projections of available supply take into account the diluent requirements for blending of heavy oil and bitumen, recycled volumes of diluent, product losses during upgrading and volumes of pentanes plus not available to the downstream market.

In Case 1, the net available supply increases from 331 000 m^3/d in 1997, to a peak of 500 000 m^3/d in 2007, it then declines gradually to a level of 410 000 m^3/d by 2025. In Case 2, the peak is slightly lower, at 440 000 m^3/d, and the decline is somewhat greater than in Case 1, with a production level of 330 000 m^3/d at the end of the projection period.

In 1997, conventional light oil represented 41 percent of the net available supply, blended heavy oil 40 percent and upgraded crude 18 percent. A common feature of both cases is the decline in conventional light production and the increasing importance of upgraded crude oil and blended heavy oil.

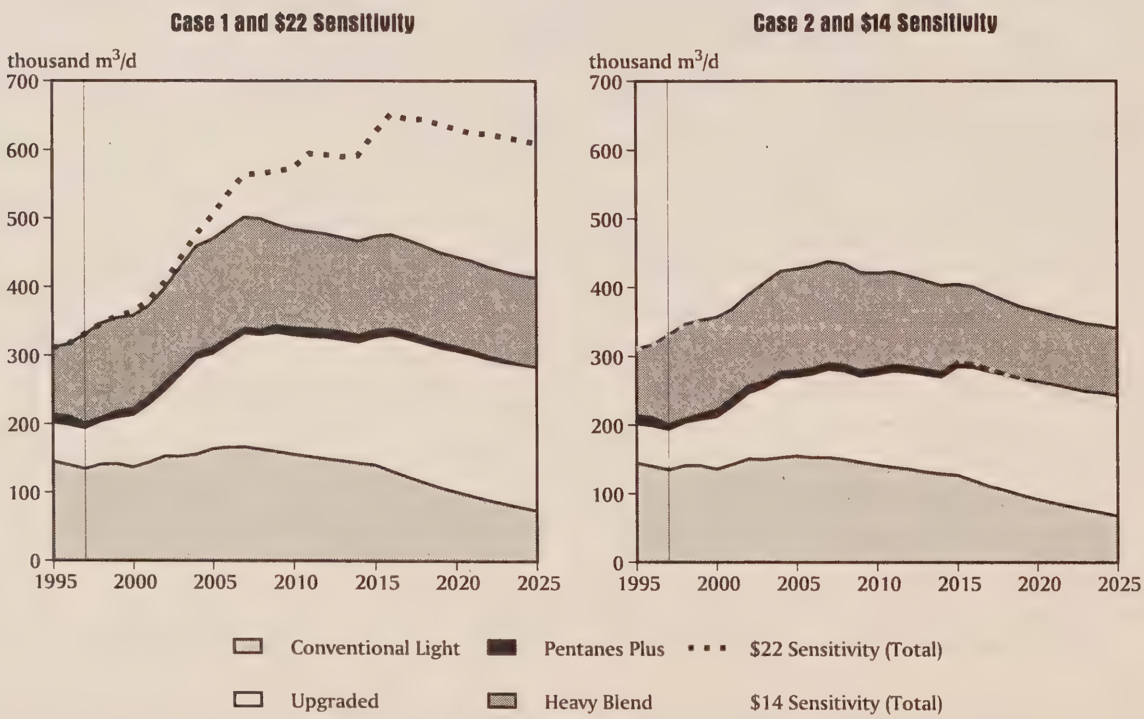
In Case 1, conventional light oil represent only 18 percent of the total by 2025, upgraded crude 50 percent and blended heavy oil 32 percent. In Case 2, conventional light makes up 20 percent of the total by 2025, upgraded crude 53 percent and blended heavy oil 25 percent.

In the \$14 Sensitivity, the net available supply is 227 000 m^3/d in 2025, 33 percent lower than in Case 2. In the \$22 Sensitivity, the net available crude oil reaches about 651 000 m^3/d by 2016 and maintains roughly that level until the end of the projection, at which point it is about 53 percent higher than in Case 1.

7.12 REFINERY FEEDSTOCK REQUIREMENTS

This section addresses the feedstock requirements for Canadian refineries. These are based on projected

Figure 7.12
Net Available Supply - Crude Oil and Equivalent



demand for petroleum products (see Chapter 3) and assumed levels of exports and imports of products.

7.12.1 Total Refinery Feedstock Requirements

Table 7.5 presents the key determinants of total refinery feedstock requirements.

Domestic Petroleum Products Demand

Total domestic demand for petroleum products was 268 000 m³/d in 1997. By 2025, it increases to 370 000 m³/d in Case 1 and to 330 000 m³/d in Case 2.

Exports and Imports of Refined Petroleum Products

Exports and imports of petroleum products will continue to play a role in balancing supply and demand. Refiners and marketers will export and import products to overcome seasonal and regional imbalances in demand and to operate refineries as efficiently as possible.

Total exports of petroleum products averaged about 49 000 m³/d in 1997. It is expected that exports will remain close to this level throughout the projection period in both cases. Nearly 70 percent of these exports will be from the Atlantic region, reflecting processing agreements and the ongoing marketing opportunities along the U.S. east coast.

In 1997, total imports of petroleum products averaged 26 000 m³/d. It is projected that some large industrial consumers and utilities in eastern Canada will continue to import heavy fuel oil for their own consumption. However, the quantities imported will be less than historical volumes, as a result of Scotian Shelf natural gas production. In addition, rising product demand in British Columbia will be met by increased product imports. Overall, it is projected that product imports will increase to 36 000 m³/d in Case 1 and to 30 000 m³/d in Case 2.

Historically, some refiners have made interregional transfers of petroleum products to satisfy regional products demand and to balance refinery operations. During the projection period, it is assumed that these transfers of refined products will continue, especially between Edmonton and British Columbia, where several refineries have closed. In addition, interregional transfers to Ontario from the Prairie provinces and Québec are expected to remain around current levels during the projection period.

Table 7.5
Refinery Feedstock Requirements and Sources
(thousand m³/d)

		2010		2025	
	1997	Case 1	Case 2	Case 1	Case 2
Demand for Petroleum Products	268	310	297	370	330
Product Exports	49	48	48	48	48
Product Imports	(26)	(29)	(27)	(36)	(30)
Inventory Change	(2)	0	0	0	0
Total Feedstock Requirements	**289**	**329**	**318**	**383**	**348**
Sources:					
Light Crude Oil	212	247	235	298	263
Heavy Crude Oil	52	60	60	63	63
Other Material	25	22	22	22	22
Total	**289**	**329**	**318**	**383**	**348**

7.12.2 Feedstock Requirements by Type of Crude Oil

Refineries in Canada generally use light crude oil to manufacture petroleum products while the bulk of Canadian heavy crude oil production is exported. Thus, in order to assess the extent to which domestic feedstock demand can be satisfied from indigenous production, it is necessary to determine supply and demand balances for light and heavy crude oils separately. In this section, heavy crude oil refers to conventional heavy crude oil or blended heavy oil while light crude oil includes conventional light and upgraded crude oil, and pentanes plus.

Light Crude Oil

Table 7.6 shows the outlook for supply and disposition of light crude oil and equivalent. It is projected that one-half of the offshore production from the east coast will be exported and that the balance will be processed in equal quantities at refineries in the Atlantic and Québec regions.

The Sarnia to Montreal pipeline was reversed in May 1999. Its initial capacity is about 16 000 m³/d and is expected to rise to 32 000 m³/d by July 2000 and to 38 000 m³/d by July 2001.

Western Canadian crude oil is assumed to be used primarily to satisfy refinery demand in western Canada

and then to supply some of Ontario's light crude oil requirements. The remaining supplies are available for export.

In 1997, production of light crude oil was 201 000 m³/d, compared with domestic refinery demand of 212 000 m³/d. In that year, Canada had exports of about 80 000 m³/d and imports of 92 000 m³/d. Imports were concentrated in eastern Canada.

In Case 1, light crude oil supply increases to 339 000 m³/d in 2010 and remains at about that level for the next five years. In Case 2, it increases to 282 000 m³/d in 2010 and to 292 000 m³/d in 2015. These increases reflect the growing production from the east coast offshore and the rising production of upgraded crude oil. After 2015, light crude oil supply declines throughout the balance of the projection period in both cases.

It is projected that total domestic requirements for light crude oil will rise to 298 000 m³/d in Case 1, and to 263 000 m³/d in Case 2, by 2025. At these levels, there will be insufficient refinery capacity in Québec, Ontario and the Prairie regions. As a result, refiners will have to increase capacity, reduce product exports or increase product imports to satisfy demand.

In Case 1, light crude oil exports peak at about 185 000 m³/d in 2010. In Case 2, they peak at nearly 150 000 m³/d in 2005. Approximately 30 000 m³/d reflect exports from the east coast offshore to U.S. markets.

Heavy Crude Oil

The outlook for the supply and disposition of heavy crude oil is presented in Table 7.7. In 1997, domestic supply of blended heavy oil was 131 000 m³/d. In Case 1, domestic supply rises to 161 000 m³/d in 2005 before declining to 132 000 m³/d in 2025. In Case 2, it increases to 148 000 m³/d in 2005. It then declines gradually throughout the projection period to approximately 98 000 m³/d in 2025.

While most Canadian refineries are designed to process light crude oil, they also use limited volumes of heavy crude oil, mainly for the manufacture of asphalt in the summer. The estimated requirements for heavy crude oil, excluding upgrader feedstock, are projected to increase marginally in both cases, from 52 000 m³/d in 1997 to 63 000 m³/d in 2025. Of this amount, imports of heavy crude oil by refineries in Québec and the Atlantic provinces are predicted to be approximately 25 000 m³/d throughout the projection period.

Exports of heavy crude oil were 103 000 m³/d in 1997. In Case 1, exports peak at 127 000 m³/d in 2005 and then drop to 94 000 m³/d in 2025. In Case 2, they are projected to increase to 115 000 m³/d in 2005 and then decline to 60 000 m³/d in 2025.

Table 7.6
Supply and Disposition of Light Crude Oil
(thousand m³/d)

		2010		2025	
	1997	Case 1	Case 2	Case 1	Case 2
Domestic Supply[1]	201	339	282	280	232
Imports	92	94	96	125	119
Total Supply	292	432	378	405	351
Total Domestic Requirements	212	247	235	298	263
Exports	80	185	143	108	88
Total Disposition	292	432	378	405	351
Net Exports (Imports)	(11)	92	47	(18)	(31)

1 Domestic supply is net of diluent requirements for heavy crude oil.

Table 7.7
Supply and Disposition of Heavy Crude Oil
(thousand m³/d)

		2010		2025	
	1997	Case 1	Case 2	Case 1	Case 2
Domestic Supply[1]	131	146	139	132	98
Imports	24	25	25	25	25
Total Supply	155	171	165	157	123
Total Domestic Requirements	52	60	60	63	63
Exports	103	111	104	94	60
Total Disposition	155	171	165	157	123
Net Exports	79	86	79	68	34

1 Domestic supply includes diluent requirements for heavy crude oil.

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CHAPTER 8

Coal

8.1 INTRODUCTION

This chapter presents the Board's outlook for coal resources, prices, markets and technological developments affecting supply and demand. Detailed information is provided in *Appendix 8: Coal.*

8.2 CANADIAN COAL RESOURCES AND RESERVES

The degree of metamorphism undergone by coal, as it matures from peat to lignite, to bituminous and sub-bituminous, and ultimately to anthracite, has an important bearing on its physical and chemical properties. This is referred to as the rank of the coal.

Low rank coals, such as lignite and sub-bituminous, are characterized by higher moisture levels and lower energy content. They are used in power generation and cement manufacturing. Higher rank coals, which include bituminous and anthracite, are lower in moisture, and higher in carbon and energy content. These coals are used in power generation and the production of coke, which is a reducing agent and heat source for the steel industry. Canadian deposits of anthracite are currently not exploited. Increasing concern over sulphur dioxide emissions and acid rain places a premium value on reserves from western Canada which generally have a low sulphur content.

Estimates of coal resources only include deposits which occur within specified limits of thickness and reflect both the economic and technical feasibility of exploitation. These estimates are commonly divided into two main categories: resources of immediate interest and resources of future interest. To be of immediate interest, resources must consist of coal seams with a combination of thickness, quality, depth and location that render them attractive for further exploration or early development. Resources of future interest tend to be more costly to produce because of either their remoteness or depth.

Almost 95 percent of resources of immediate interest are located in western Canada (Table 8.1). About 60 percent of these consist of low-quality lignite and sub-bituminous coal deposits, located mostly in Alberta. Higher quality bituminous resources of immediate interest are found in British Columbia; substantial deposits also occur in Alberta and Nova Scotia. Resources of future interest are concentrated at greater depth in the plains region of Alberta and in the Arctic (Appendix 8).[1]

Reserves are deposits that have been adequately delineated through exploration and sampling, and can be considered economic for exploitation using current technology. The most recent reserves estimate was released in 1987, for the year ending 1985 (Table 8.2). Remaining reserves would be about 90 times the 1997 Canadian production of 79 megatonnes. Lignite reserves are mainly found in Saskatchewan, whereas all sub-bituminous reserves are located in Alberta. Most of Canada's bituminous reserves are in British Columbia with smaller volumes located in Alberta and Nova Scotia.

Table 8.1
In-Place Coal Resources of Immediate Interest
(megatonnes)

	Low Volatile Bituminous -Anthracite	Medium-Low Volatile Bituminous	High-Medium Volatile Bituminous	High Volatile Bituminous	Lignite-Sub-Bituminous	Total
British Columbia	1 610	9 270	7 190	645	1090	19 805
Alberta	815	3 515	1 710	7 420	33 475	46 935
Saskatchewan	-	-	-	-	7 595	7 595
Ontario	-	-	-	-	180	180
New Brunswick	-	-	75	-	-	75
Nova Scotia	-	-	1 405	-	-	1 405
Yukon and District of Mackenzie	90	-	150	350	2 290	2 880
Canada	2 515	12 785	10 530	8 415	44 630	78 875

Source: *Coal Resources of Canada, Paper 89-4*, Geological Survey of Canada, 1989.

1 Through its National Inventory, the Geological Survey of Canada is undertaking a complete reassessment of Canada's coal resources which incorporates all available geological data from industry and provincial governments. This inventory aims to assess the resource availability by incorporating rigorous economic criteria based on end use and available mining equipment, as well as surface land use and other environmental factors which restrict access to sources.

8.3 COAL PRICES

Canada is both an importer and exporter of coal; thus, domestic prices tend to reflect developments in international markets. Many countries, including the U.S., have unused productive capacity that can be activated when prices rise sufficiently. This potential production tends to limit sustained price increases.

The principal Canadian purchasers of coal are electric utilities. The prices they have paid have declined substantially in real terms over the past 10 to15 years (Figure 8.1), reflecting productivity improvements in coal mining operations, industry rationalization and improved productivity in rail transportation. Transportation costs are typically half, or more, of the delivered price of coal.

Coal prices vary among provinces due to transportation costs, quality differences and specific contractual terms. In recent years, average Canadian prices have fluctuated between $(1997) 1.15 and $1.20 per gigajoule. The prices of domestic and imported bituminous coal in Ontario have been between $1.80 and $2.20 per gigajoule. Utilities in Alberta and Saskatchewan have been paying $0.50 to $1.00 per gigajoule for sub-bituminous coal and lignite.

It is assumed that productivity improvements will continue, but at a slower pace than in the past 15 years. Later in the projection period, coal prices stabilize or increase due to the rising prices of natural gas, a competitive fuel in the electricity generation sector. In Case 1, real coal prices decline by about 20 percent between 1997 and 2015 before stabilizing. In Case 2, productivity improvements are less and the competitive ceiling formed by gas prices is higher; thus the near-term decline is less and prices increase longer term. In neither case do prices achieve the levels of the early 1990s.

8.4 DOMESTIC DEMAND

In Case 1, total domestic coal demand rises from 56 megatonnes (Mt) in 1997 to 62 Mt in 2025, an average annual growth rate of 0.4 percent per year. In Case 2, it declines to 52 Mt by 2025, an average annual decline of 0.3 percent per year (Figure 8.2).

Electricity Generation

In 1997, electricity generation consumed 49 Mt of coal, about 84 percent of domestic coal demand. Ontario, Alberta and Saskatchewan accounted for 91 percent of this consumption, with the remainder in Nova Scotia and New Brunswick. Coal-fired generation

Table 8.2
Remaining Established Coal Reserves, Year-end 1985
(megatonnes)

	Thermal[2]				Metallurgical[3]	
	Lignite	Sub-Bituminous	Bituminous	Total	Bituminous	Total
British Columbia	566	-	433	999	1 563	2 562
Alberta[1]	-	1 100	1 300	2 400	230	2 630
Saskatchewan	1 670	-	-	1 670	-	1 670
New Brunswick	-	-	21	21	-	21
Nova Scotia	-	-	300	300	115	415
Canada	2 236	1 100	2 054	5 390	1 908	7 298

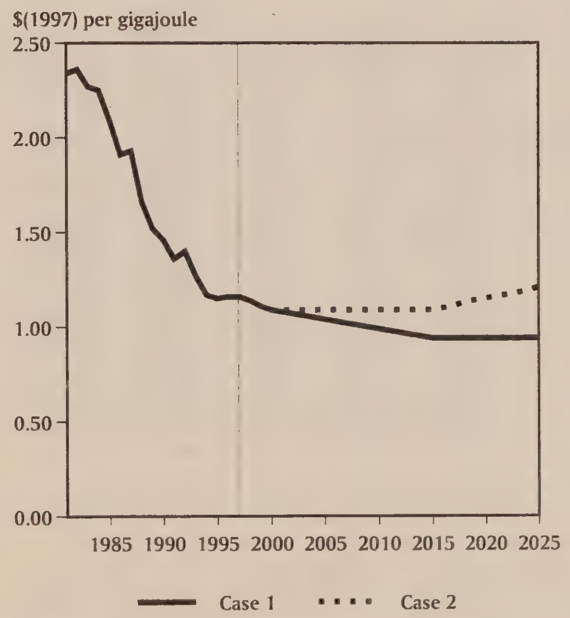
1 The Alberta Energy and Utilities Board estimates of coal reserves, within mine permit boundaries, are 2 628 megatonnes as of December 1993 (EUB ST9-94-31).

2 Thermal coals generally include the lignite-sub-bituminous, high volatile bituminous and low volatile bituminous-anthracite classes.

3 Metallurgical coals generally include the medium-low volatile bituminous and high-medium volatile bituminous classes.

Source: *Coal Mining in Canada, 1986, Report 87-3E*, CANMET, September 1987

Figure 8.1
Canadian Electric Utility Coal Prices



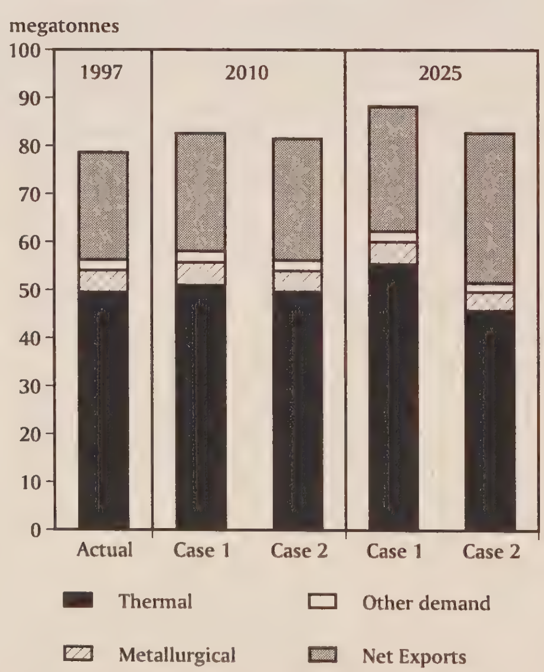
is expected to remain competitive with other fuels, particularly in existing facilities, although little growth is expected (see Chapter 4).

In Case 1, the demand for thermal coal is expected to increase in Ontario, Saskatchewan and Alberta. In Nova Scotia and New Brunswick, it is anticipated that Scotian Shelf gas will penetrate the electricity generation market, causing a reduction in coal use. In Case 1, the increase in Canadian demand for thermal coal averages 0.4 percent per year during the projection period. In Case 2, demand is lower than in Case 1 because of lower electricity demand; by 2025, it is about 9 Mt lower.

Metallurgical Demand

Metallurgical demand is currently about 11 percent of the domestic requirement. Almost all of this is accounted for by the iron and steel industry in Ontario. A moderate increase in demand is expected, but this will be influenced by improving technology in the steel making process. Two main examples are pulverized coal injection, which effectively reduces the coal requirement per tonne of steel produced, and the use of electric arc furnaces, which process scrap steel and thus have no requirement for metallurgical coal. Metallurgical demand is lower in Case 2; it declines longer term as the result of greater efficiency improvements compared to Case 1.

Figure 8.2
Canadian Coal Demand and Production[1]



1 Production is equal to the sum of domestic demand (thermal, metallurgical and other) and net exports.

Other Demand

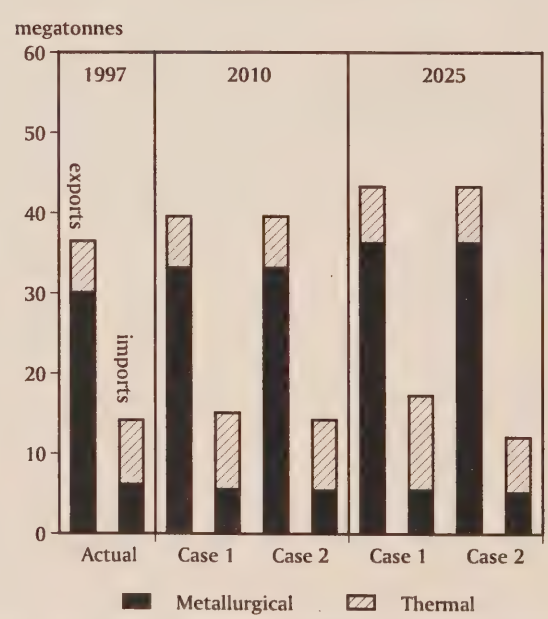
In 1997, under 2 Mt of coal were used to generate process heat in the cement, smelting and other industries, mostly in Québec, Ontario and British Columbia. Little growth is projected in either case, due to users' preference for other fuels.

8.5 COAL TRADE

In 1997, exports were 36 Mt while imports were 14 Mt. Canada is expected to remain a net exporter in Case 1 and in Case 2 (Figure 8.3).

Metallurgical coal accounted for 82 percent of exports in 1997, mostly from Alberta and British Columbia to Japan and the Republic of Korea. Most thermal coal exports were also shipped to Japan and Korea (see Appendix 8). Total exports are projected to increase to 43 Mt in 2025 in Case 1 and Case 2, an average annual growth rate of 0.6 percent per year. There are a number of uncertainties associated with this outlook, including the international prospects for the steel industry and the demand for coal in electricity generation. Canada's share of the world market could decline due to relatively high transportation costs.[a]

Figure 8.3
Coal Exports and Imports



Ontario imports most of its thermal and metallurgical requirements and much smaller amounts of thermal coal are imported to Québec, Nova Scotia and New Brunswick. Imports occur because supplies from the Appalachian region, and to some extent Wyoming and Montana, are more competitive than western Canadian coal in eastern Canada. A minor amount is also imported from Columbia. In Case 1, imports increase to 17 Mt by 2025; in Case 2, they decline to 12 Mt, reflecting the lower electricity generation requirements and lower demand for metallurgical coal.

8.6 COAL PRODUCTION

The coal production outlook is the outcome of the analysis of domestic demand and trade. Between 1997 and 2025, production increases on average by 0.4 percent per year in Case 1 and by 0.2 percent per year in Case 2, reaching 88 Mt and 83 Mt respectively in 2025 (Figure 8.2). The western Canadian share of production remains at about 97 percent with the remainder coming from Nova Scotia and New Brunswick.

8.7 COAL TECHNOLOGY

There are a number of technologies currently under development that could increase the competitiveness of coal. Two important combustion technologies are integrated gasification combined-cycle (IGCC) and pressurized fluidized bed combined-cycle (PFBCC). In 1998, there were four PFBCC plants in operation in Europe and Japan and five IGCC plants in operation in the U.S. and Europe.[b] It is expected that cost reductions will be required for widespread commercial applications. Sulphur dioxide and nitrous oxide emissions can also be reduced by advances in the pre-combustion stage (e.g., coal cleaning) and post-combustion (e.g., selective catalytic reduction and selective non-catalytic reduction).

As part of the A&R sensitivity, the Board assumes that IGCC will be the preferred technology in all Canadian coal plants built or repowered after 2010. This would increase the efficiency of coal generation by up to 50 percent relative to conventional coal plants.

REFERENCES

a *World Energy Outlook*, 1998 Edition, International Energy Agency.

b *Coal Information* (1988 Edition), International Energy Agency.

CHAPTER 9

Sources and Uses of Energy

9.1 INTRODUCTION

This chapter presents the future trends in Canadian energy supply, demand and trade. Detailed data can be found in *Appendix 9: Sources and Uses of Energy*. The purpose of this chapter is to illustrate the balance between domestic energy production and imports with domestic demand and exports (Figure 9.1).

In moving from primary sources of energy to end use demand, the sources of primary energy are identified, consisting of domestic primary energy production and imports. Subtracting exports from these energy sources leaves domestic demand for primary energy. To derive end use demand from primary energy, intermediate uses of energy in transforming one energy form to another and energy used by suppliers in providing energy to market are deducted.

9.2 PRIMARY PRODUCTION

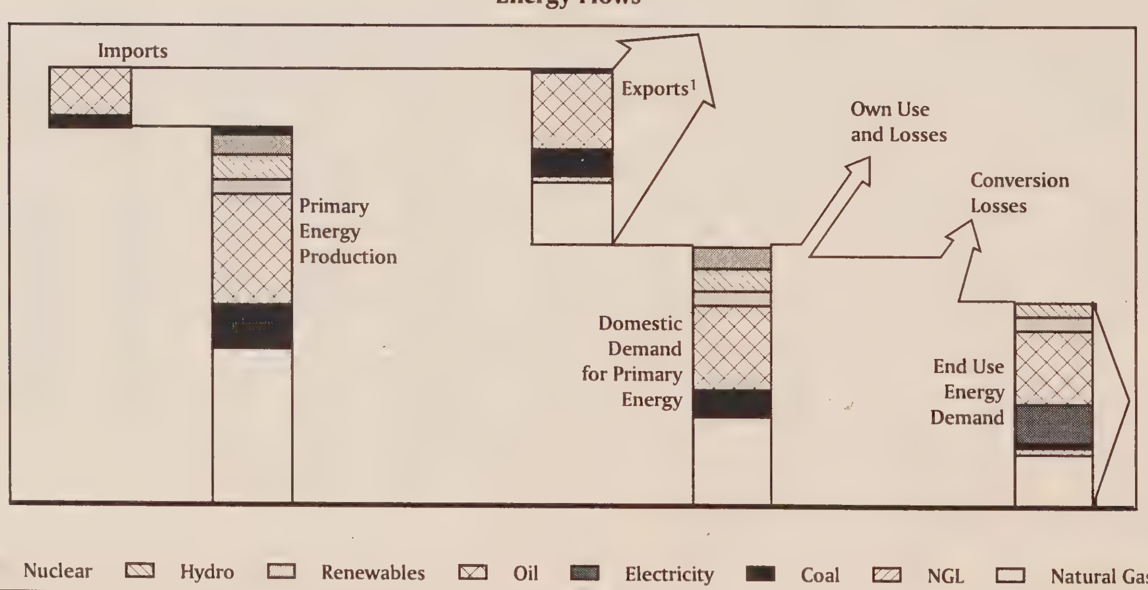
Production of primary energy is projected to increase by approximately 1.4 percent per year from 1997 to 2025 in Case 1 and by 0.9 percent in Case 2 (Figure 9.2). These projections are lower than the average annual production growth of 4.5 percent in the 1990s.

In Case 1, production reaches a maximum in 2020 and then declines by about 0.4 percent per year between 2020 and 2025. In Case 2, the decline is more pronounced; production peaks in 2015 and then declines by almost 1 percent per year between 2015 and 2025.

In both cases, the shares of production of the various energy sources remain fairly stable. Renewable fuels maintain a 3 to 4 percent share of total energy production, while hydro maintains a share of 6 to 7 percent. Nuclear production falls marginally in Case 1, while in Case 2, its share holds steady at about 6 percent.

In both cases, the share of natural gas continues to grow from approximately 37 percent in 1997 to over 45 percent in 2025. In Case 1, the share of oil climbs from 30 percent in 1997 to 31 percent in 2010, but then declines to 25 percent by 2025. In Case 2, oil maintains its share initially, and then declines to 24 percent by

Figure 9.1
Energy Flows



1 Exports include fuel and losses associated with electricity exports.

2025. The share of coal in total energy production declines from 12 percent in 1997 to 10 percent in 2025 in Case 1 and to 11 percent in Case 2.

9.3 IMPORTS

Oil and coal dominate energy imports. Imports of these two fuels accounted for 96 percent (2 531 PJ) of fuel imports in 1997 and continue to represent over 96 percent of imports for most of the projection period. In 1997, coal imports were 419 PJ. By 2025, coal imports rise to 509 PJ in Case 1, but decline to 404 PJ in 2025 in Case 2. In both cases, imports of crude oil and refined petroleum products remain close to 1997 levels (2 112 PJ) until 2015, at which time they increase significantly, to eventually reach 2 616 PJ in Case 1 and 2 451 PJ in Case 2 by 2025.

Currently, natural gas and NGL imports are negligible, representing less than 1 percent of total domestic energy demand. It is expected that they will remain at low levels throughout the study period. However, in Case 2, NGL imports could rise to over 200 PJ by 2025.

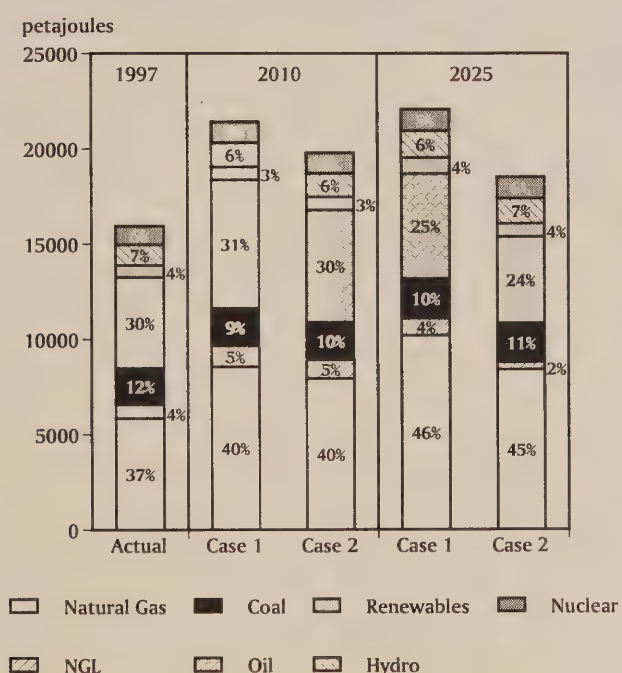
9.4 PRIMARY ENERGY DEMAND

Domestic primary energy demand is projected to grow at an average annual rate of about 1.6 percent between 1997 and 2025 in Case 1 and about 1.0 percent in Case 2 (Figure 9.3). Both cases show lower demand growth than the period 1990-1997, when growth averaged approximately 2.2 percent per year. The mix of fuels is not expected to change dramatically. Renewables, hydro and nuclear energy shares remain fairly stable. In Case 1, the share of natural gas rises from 30 percent in 1997 to 36 percent by 2025, while the share of oil declines from 33 percent in 1997 to 31 percent in 2025. In Case 2, the share of natural gas rises to 34 percent by 2025, while the share of oil falls slightly to 32 percent by 2025. In both cases, the share of coal in domestic demand will decline slightly from 10 percent in 1997 to 8 percent in 2025.

9.5 EXPORTS

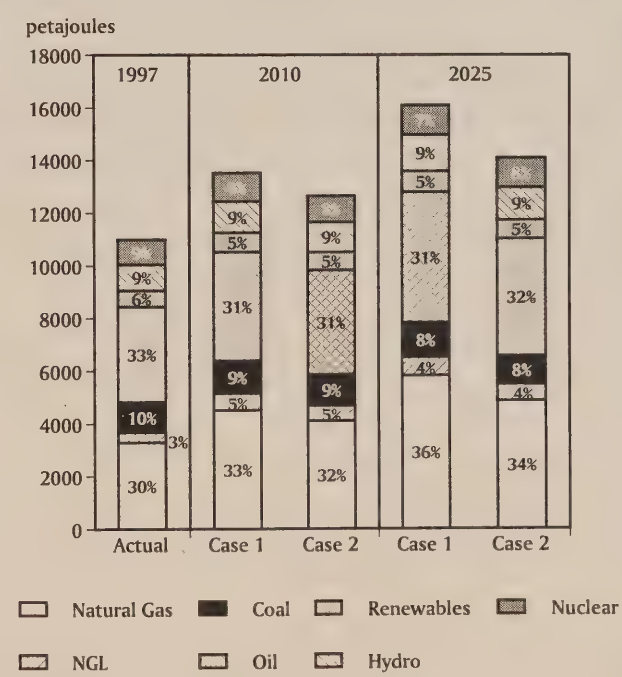
Exports are an important determinant of Canadian energy production. In 1997, about half of primary energy production was exported. This share is

Figure 9.2
Energy Production by Energy Source[1]



1 Natural Gas and Oil Production figures have been adjusted to remove NGL production, so that NGL production may be shown separately

Figure 9.3
Primary Domestic Energy Demand by Energy Source



projected to decline by 2025, to 44 percent in Case 1 and to 42 percent in Case 2. Crude oil and refined petroleum products accounted for about 42 percent of gross exports; natural gas for 38 percent and coal for 14 percent.

In both cases, the share of natural gas is expected to exceed that of oil by 2015. In Case 1, natural gas is expected to account for 48 percent of gross exports and oil for 36 percent by 2025. In Case 2, natural gas could account for 47 percent of gross exports, while oil could account for 35 percent in 2025. In both cases, the share of coal declines in the near term, but then stabilizes or increases. By 2025, the share of coal is 13 percent in Case 1 and 17 percent in Case 2. In both cases, NGL represent about 4 percent of gross exports until 2015, at which point they decline.

9.6 NET EXPORTS

Net exports are expected to increase by about 4.7 percent per year from 1997 to 2010 in Case 1; but decline by about 1.4 percent per year between 2010 and 2025 (Table 9.1). In Case 2, net exports are expected to increase at an annual average rate of about 3.3 percent up to 2010. After 2010, they decline by an average of 2.4 percent per year. Net electricity trade is expected to continue to represent a small proportion of production. Net exports of NGL will increase in the first half of the study period. In Case 1, they increase from 277 PJ in 1997 to a high of 446 PJ in 2015, after which time they begin to decline. In Case 2, they peak in 2010 at 394 PJ and then decline to a net import position by 2025.

The energy mix for net exports changes over the study period. Natural gas consistently remains the largest component of Canada's net fuel exports. In 1997, natural gas accounted for 56 percent of net energy exports. By 2025, this share grows to 70 percent in Case 1 and to 77 percent in Case 2. In 1997, crude oil and refined petroleum products accounted for 23 percent of net exports. In Case 1, this share grows to about 35 percent by 2005 and then declines to 14 percent by 2025. In Case 2, this share grows to about 32 percent by 2005 and shrinks to 7 percent by 2025. Coal accounted for 13 percent of net exports in 1997. This share is expected to decline to about 10 percent in the middle of the study period for both cases, and then rise to 12 percent by 2025 in Case 1 and 20 percent in Case 2.

Canada is expected to remain a net exporter of energy throughout the study period. With the exception of NGL, Canada is expected to have a trade surplus for each energy source.

Table 9.1
Net Energy Exports
(petajoules)

		2010		2025	
	1997	Case 1	Case 2	Case 1	Case 2
Coal	693	760	786	810	963
Electricity	115	62	99	64	59
Natural Gas	2 997	4 062	4 181	4 783	3 715
NGL	277	439	394	183	(209)
Crude Oil & Products	1 228	2 821	2 126	966	342
Total	5 310	8 544	7 586	6 806	4 870

CHAPTER 10

Emissions of Greenhouse Gases

10.1 INTRODUCTION

The greenhouse gas (GHG) emissions are a result of the projections of supply and demand contained in this report. The results include the impact of known programs such as the Voluntary Challenge and Registry (VCR).

The Board recognizes the interest and importance of the Kyoto Protocol,[1] but its projections did not attempt to reach the specified targets. The emissions analysis assesses the potential impacts of the two main cases, Current Demand Trends/Low Cost Supply Case (Case 1) and the Accelerated Demand Efficiency/Current Supply Trends Case (Case 2), as well as the effects of a higher penetration of alternate technologies and renewable fuels (A&R Sensitivity).

During the consultations, views were expressed that other emissions, such as sulphur dioxide and oxides of nitrogen, should be included. However, other agencies, such as Environment Canada, are better equipped than the Board to provide such projections. This report focuses on GHG only, which include carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O).

10.2 METHODOLOGY

Greenhouse gas emissions are estimated from end use energy demand in the residential, commercial, industrial and transportation sectors. These emissions are generated by applying emission factors to fuel demand projections. The factors are, for the most part, obtained from Environment Canada[a] and Natural Resources Canada (NRCan) and are listed in Appendix 10.

In addition to emissions from the end use sectors, emissions from fossil fuel production and electricity generation are also calculated. For the oil and gas sector, including oil sands production, the methodology applied in the 1994 Report[b] was used. It is based on a study conducted by the Canadian Association of Petroleum Producers[c] (CAPP), with further development by CAPP and Environment Canada. The approach uses a model developed by NRCan with the appropriate emissions factors listed in Appendix 10. Commitments made by fossil fuel production companies to reduce their emissions under the VCR program are explicitly included in the model.

Emissions factors for CO_2 stripped from natural gas production are based on the emission levels in the national inventory[d] for the period 1993 to 1996. Average provincial CO_2 emissions for that period were divided by the average provincial marketable gas production for the same period to obtain a provincial emission factor. This factor was then applied to the projections of provincial natural gas production. For new gas production from the Scotian Shelf, the average Canadian emission factor was assumed.

Fugitive emissions of methane from open pit coal mines in western Canada and underground mines in eastern Canada were obtained from the emission inventories published by Environment Canada.[d] Using the aggregate mined coal tonnage from 1990 to 1995, emission factors were derived and applied to the projections of coal production.

By convention, CO_2 emissions due to the combustion of biomass are not included in the national inventory, if a nation's forests are managed in a sustainable manner. Emissions from wood, hog fuel and pulping liquor are calculated, but are not included in the tabulation of sectoral emissions.

Although carbon dioxide is the predominant anthropogenic greenhouse gas, methane and nitrous oxide have a much stronger impact, molecule for molecule, on warming the atmosphere. These gases are compared to CO_2 by using the Global Warming Potential (GWP) value which is defined as the measure of the warming effect that a gas has on the atmosphere, relative to CO_2. The GWP of methane is 21 and that of N_2O is 310. The emissions of these gases are multiplied by their

1 The Kyoto Protocol was signed in December 1997. Canada agreed to cut its GHG to 6 percent below the 1990 levels by 2008-2012. The agreement has not been ratified.

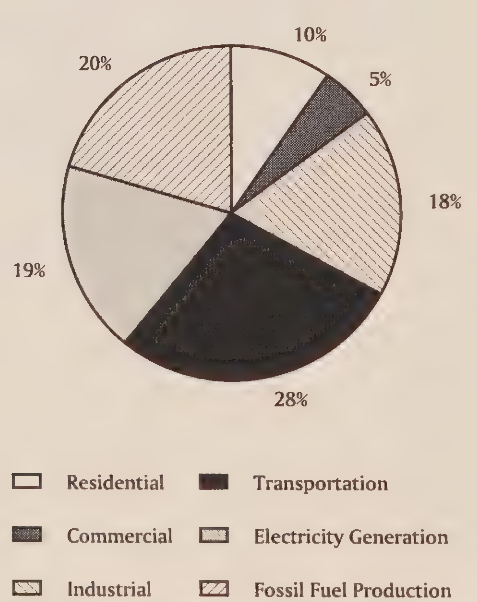
respective GWP to obtain a CO_2 equivalent. In the discussions, the CO_2 equivalent value for CH_4 and N_2O is reported.

10.3 1997 EMISSIONS

In 1997, total greenhouse gas emissions from the consumption and production of energy were 583 megatonnes (Mt). Of this total, 527 Mt were CO_2, 39 Mt of CO_2 equivalent were CH_4 and 18 Mt of CO_2 equivalent were N_2O.

Figure 10.1 shows the sectoral emissions (including CH_4 and N_2O) for 1997. The transportation sector is the largest emission source at 163 Mt. The industrial sector emitted 106 Mt, the electric power industry 109 Mt, residential sources 56 Mt and commercial sources 30 Mt. The fossil fuel production industries emitted 120 Mt of GHG of which 80 Mt was CO_2, 39 Mt were methane and 1.3 Mt were N_2O. In the fossil fuel production industries, the oil production and distribution sector contributed 42 Mt, the natural gas production and distribution sector contributed 73 Mt, and the remaining 5 Mt were distributed between fugitive methane from coal mining, well servicing and flaring.

Figure 10.1
GHG Emissions by Sectors
Total 583Mt (CO_2 Equivalent)



10.4 EMISSIONS PROJECTIONS

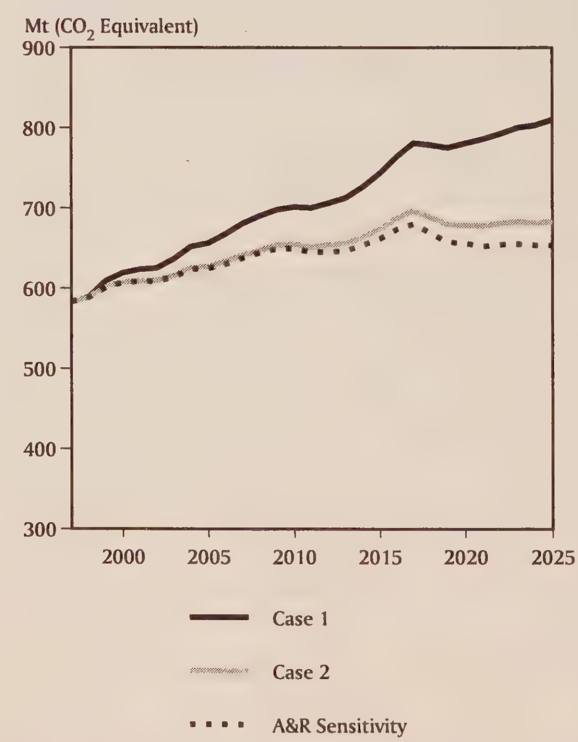
10.4.1 Overall Results

A comparison of the total emissions projected for Case 1, Case 2 and the A&R Sensitivity is shown in Figure 10.2. In all cases, it is expected that there will be a steady increase in GHG emissions over the period. In Case 1, the emissions are projected to increase by 1.2 percent per year to reach 811 Mt in 2025.[2] In Case 2, they grow at 0.6 percent per year and reach 683 Mt in 2025, while in the A&R Sensitivity, they grow at 0.4 percent per year and reach 654 Mt in 2025.

CO_2 emissions contribute most to the overall emissions, particularly prior to 2010. For Case 1, the average CO_2 growth rate is 1.6 percent per year to 2010, but only 1.0 percent per year in the 2010 to 2025 period. In Case 2, the CO_2 growth rates are 1.0 percent per year in the first half of the period, and 0.3 percent per year in the second half. In the A&R Sensitivity, emissions grow at 0.1 percent per year in the 2010 to 2025 period.

N_2O emissions grow at a constant rate of approximately 1.3 percent per year in all cases. On the other

Figure 10.2
Total Greenhouse Gas Emissions



2 Detailed results are presented in *Appendix 10: Emissions*

hand, methane emissions decline over the full period in all cases. This effect is largely attributable to the impact of the VCR on emissions in the upstream oil and gas sectors. This decline is more significant in the second half of the projection period for Case 2 and the A&R Sensitivity, reflecting lower levels of demand and production.

10.4.2 Sectoral Emissions

Sectoral emissions for Case 1 and Case 2 are shown in Figure 10.3. In both cases, the transportation sector is the largest component, followed by fossil fuel production. Other sectors maintain their relative share of total emissions. In all sectors, emission levels rise above 1997 levels.

It is useful to consider the difference between the two cases on a sector by sector basis. Figure 10.4 shows the percent reductions in total emissions from Case 1 to Case 2, in each of the six sectors, for the years 2010 and 2025.

Residential

By 2025, GHG emissions in the residential sector rise from 56 t in 1997 to 70 Mt in Case 1, 61 Mt in Case 2 and to 59 Mt in the A&R Sensitivity. By 2010, due to lower levels of energy demand, emissions are 8.4 percent lower in Case 2 than in Case 1; they are 13 percent lower by 2025. In the A&R Sensitivity, the increased use of wood-pellet stoves, for which emissions are not included, combined with increased penetration of solar heating systems, leads to emissions that are 2.2 percent lower than in Case 2.

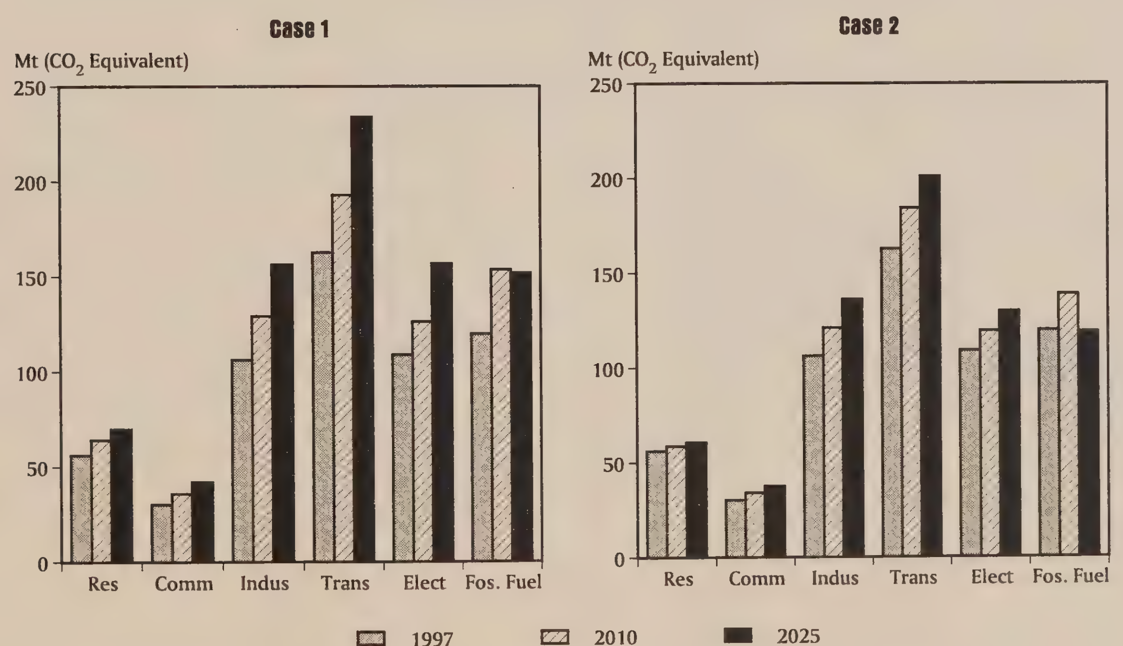
Commercial

In the commercial sector, emissions increase from 30 Mt in 1997 to 42 Mt in Case 1 and to 37 Mt in Case 2 and the A&R Sensitivity by 2025. Due to lower energy requirements, emissions in Case 2 are about 5 percent lower than in Case 1 by 2010; this difference increases to 11 percent by 2025. In the A&R Sensitivity, there is a slight reduction from the levels in Case 2, attributable to increased penetration of solar heating technologies.

Industrial

In the industrial sector, emissions increase from 106 Mt in 1997 to 156 Mt by 2025 in Case 1, to 136 Mt in Case 2 and to 133 Mt in the A&R Sensitivity. By 2025, energy demand in Case 2 is 11 percent lower than in Case 1 while emissions are 13 percent lower. This is due in part to the increased market share of natural gas, which results from stable gas demand in bitumen extraction. By 2025, emissions are 2 percent lower in

Figure 10.3
Sectoral GHG Emissions



the A&R Sensitivity than in Case 2, due to the increased penetration of hog fuel and solar energy.

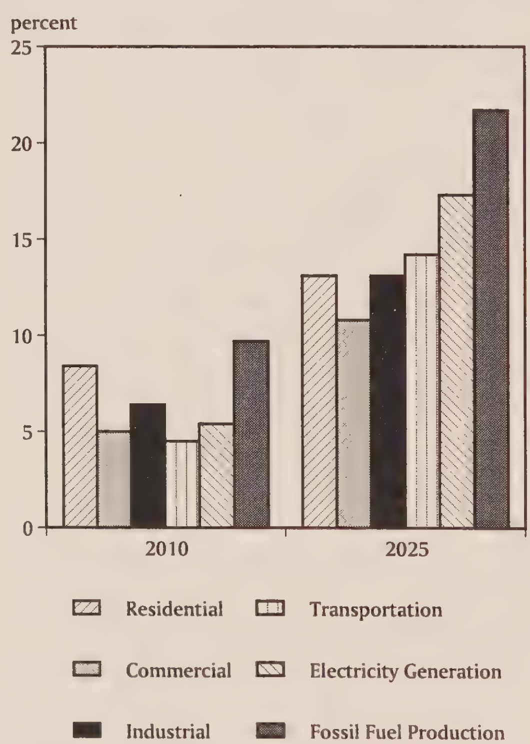
Transportation

In Case 1, emissions increase form 163 Mt in 1997 to 234 Mt by 2025, to 201 Mt in Case 2 and to 190 Mt for the A&R Sensitivity. By 2010, emissions are 4.5 percent lower in Case 2 than in Case 1. By 2025, the difference is 14.2 percent. The difference is caused by stronger improvements in fuel economy, which are accelerated over time with the greater penetration of hybrid electric vehicles and fuel cell vehicles. In the A&R Sensitivity, emissions are 1 percent lower than in Case 2 by 2010 and 4.5 percent lower by 2025. Earlier and greater penetration of hybrid electric vehicles and fuel cell vehicles explains this difference.

Electric Power Generation

By 2025, GHG emissions increase from 109 Mt in 1997 to 157 Mt in Case 1, to 130 Mt in Case 2 and to 115 Mt in the A&R Sensitivity. Although total electrical demand is almost 10 percent lower in Case 2 than in Case 1 by 2025, emissions are projected to be 17 percent lower. Much of the lower growth in emissions is due to the proportionally enhanced use of hydro and to a larger shift from coal to natural gas for new generation in Ontario and Alberta. In the A&R Sensitivity, emissions are projected to be 1.6 percent lower than in Case 2 by 2010 and 9 percent lower by 2025. This is caused by increased use of renewable energy sources such as wind, small hydro and biomass. This is evidenced by the substantial shift of emissions into the biomass sector. In Case 1 and Case 2, biomass emissions remain constant at 2 to 3 percent of total electric power emissions, while in the A&R Sensitivity, they increase to over 3 percent of the total by 2010 and 8 percent by 2025.

Figure 10.4
Sectoral Percent Reduction from Case 1 to Case 2



Fossil Fuel Production

In the fossil fuel sector, differences between Case 1 and Case 2 are most striking. There are no differences between Case 2 and the A&R Sensitivity, as it is assumed that production of fossil fuels is the same in these cases. In Case 1, emissions increase from 120 Mt in 1997 to 152 Mt by 2025 and to119 Mt in Case 2. Emissions in Case 2 are 10 percent lower than in Case 1 by 2010, and 22 percent lower by 2025. This is caused by lower levels of production for all fossil fuels, except conventional light crude oil after 2018, in Case 2 than in Case 1. In both cases, these reductions are influenced by the impact of VCR-related initiatives. In Case 2, lower levels of upgraded crude production are assumed and new projects come on stream later than in Case 1, which has the most significant impact on the levels of emissions.

REFERENCES

a *Inventory Methods Manual for Developing Canadian Greenhouse Gas Emissions Estimates*, prepared by ORTECH International Corporation for Environment Canada, 1994.

b *Canadian Energy Supply and Demand 1993 - 2010, Technical Report*, National Energy Board, 1994

c *A Detailed Inventory of CH4 and VOC Emissions From Upstream Oil and Gas Operations in Alberta*, D. J. Picard, B.D. Ross and D. W. H. Koon, 1992.

d *Trends in Canada's Greenhouse Gas Emissions 1990-1995*, A. P. Jaques, Environment Canada, 1997.

Glossary

Associated Gas	*(Gaz associé)* Natural gas which overlies and is in contact with crude oil in a reservoir.
Base Load Capacity	*(Capacité de production de la charge de base)* Electricity generating equipment which operates to supply the load over most of the year.
Biomass	*(Biomasse)* Organic material such as wood, crop waste, municipal solid waste, hog fuel and pulping liquor, processed for energy production.
Bitumen	*(Bitume)* A highly viscous mixture, mainly of hydrocarbons heavier than pentanes. In its natural state, it is not usually recoverable at a commercial rate through a well.
Blended Heavy Oil	*(Pétrole brut lourd mélangé)* Heavy crude oil to which diluent has been added in order to reduce its viscosity to meet pipeline specifications.
Capacity (Electricity)	*(Capacité [électricité])* The maximum amount of power which a device can generate, utilize or transfer, usually expressed in megawatts.
Coal Bed Methane	*(méthane de filon houiller)* The naturally occurring, dry gas produced during the transformation of organic material into coal, which is primarily methane.
Co-generation	*(Coproduction)* A facility which produces process heat as well as electricity.
Combined-Cycle Generation	*(Production d'électricité par cycle combiné)* The production of electricity using simultaneously combustion turbine and steam turbine generating units.
Conventional Crude Oil	*(Pétrole brut classique)* A liquid mixture mainly of hydrocarbons heavier than pentanes that can be produced through a well using normal production practices and without altering its viscous state.
Conventional Natural Gas	*(Gaz naturel classique)* Natural gas occurring in a normal porous and permeable reservoir which, at a particular point in time, can be technically and economically produced using normal production practices.
Core Market (Gas)	*(Marché captif [gaz naturel])* The part of the gas market that does not possess fuel switching capability in the near-term; typically, residential, commercial and small industrial users.
Cumulative Production	*(Production cumulative)* The total amount of hydrocarbons produced to a given date.
Deliverability	*(Productibilité)* See Productive Capacity.
Efficiency-Adjusted Price	*(Prix corrigé en fonction du rendement)* The implicit price of a fuel that results after adjusting its input price for its efficiency in a given end use.
Electricity Generation	*(Production d'électricité)* The amount of electric energy, usually expressed in terawatt hours, produced in a given period.

Electricity Wheeling	*(Électricité en transit)* The transmission of power belonging to one utility through the transmission grid of another one.
Emission Factor	*(Facteur d'émission)* An estimate of the rate at which a substance is released to the atmosphere as a result of some activity.
End Use Demand (or Secondary Demand)	*(Demande pour utilisation finale [ou demande secondaire])* Energy used by consumers for residential, commercial, industrial and transportation purposes, and hydrocarbons used for non-energy purposes.
Energy Intensity	*(Intensité énergétique)* For the overall economy, the industrial and the commercial sectors, it is defined as the amount of energy used per unit of real GDP. In the residential sector, it is energy use per household.
Fossil Fuels	*(Combustibles fossiles)* Hydrocarbon based fuel sources such as coal, natural gas, natural gas liquids and oil.
Frontier Areas	*(Régions pionnières)* Generally, the northern and offshore areas of Canada.
Fuel Economy	*(Économie de carburant)* The average amount of fuel consumed by a vehicle to travel a certain distance (measured in L/100km).
Fuel Efficiency	*(Rendement du combustible)* The ratio of useful energy produced when a fuel is burned to the theoretical energy content of the fuel.
Fugitive Emission	*(Émission fugitive)* Any gaseous emission from other sources than combustion (e.g., escape of gases from pipeline valves).
Greenhouse Effect	*(Effet de serre)* An atmospheric phenomenon through which incoming solar short-wave radiation passes relatively unimpeded, but long-wave radiation emitted from the warm surface of the earth is partially absorbed, adding net energy to the lower atmosphere and underlying surface, thereby increasing their temperatures.
Greenhouse Gases (GHG)	*(Gaz à effet de serre [GES])* Gases which actively contribute to the atmospheric greenhouse effect.
Heating Degree Day	*(Degré-jour de chauffage)* A measure of the extent to which the average daily temperature is below 18°C. It is used to indicate the amount of space heating required.
Heavy Crude Oil	*(Pétrole brut lourd)* Generally, a crude oil having a density greater than 900kg/m^3.
Heavy Fuel Oil	*(Mazout lourd)* In this report, includes bunker fuel oils (No. 5 and No. 6 fuel oils) and industrial fuel oil (No. 4 fuel oil).
Hog Fuel	*(Résidus de bois)* Fuel consisting of pulverized bark, shavings, sawdust, low grade lumber and lumber rejects from the operation of pulp mills, saw mills and plywood mills
Independent Power Producers	*(Producteurs d'électricité indépendants)* Operators of non-utility electric generation facilities.
Input Prices (or Retail Prices)	*(Prix d'alimentation [ou prix de détail])* The price of a fuel paid by the end user.

Integrated Mining/Upgrading Plant	*(Exploitation minière et valorisation intégrée)* A combined mining and upgrading operation where oil sands are mined from open pits. The bitumen is then separated from the sand and upgraded by a refining process.
in situ Recovery	*(Récupération in situ)* The process of recovering crude bitumen from oil sands other than by surface mining.
Light Crude Oil	*(Pétrole brut léger)* Generally, crude oil having a density of less than 900 kg/m3. Also, a collective term used to refer to conventional light crude oil, upgraded crude oil and pentanes plus.
Light Fuel Oil	*(Mazout léger)* Furnace fuel oil (No. 2 fuel oil).
Liquefied Petroleum Gases (LPG)	*(Gaz de pétrole liquéfié [GPL])* A mixture of natural gas liquids, typically propane and butanes.
Load Factor	*(Facteur de charge)* The ratio of the average load during a designated period to the peak or maximum load during that same period (usually expressed as a percent).
Marginal Cost (or Incremental)	*(Coût marginal)* The cost associated with producing one additional unit of output.
Marketable Natural Gas	*(Gaz naturel commercialisable)* Natural gas which meets specifications for end use. It excludes field and plant fuel and losses. Its heating value may vary depending upon its composition.
Methyl Tertiary Butyl Ether (MTBE)	*(Éther méthyltertiobutylique)* A chemical additive derived from butane that is used to enhance the oxygenate levels of motor gasoline.
Miscible Flooding	*(Injection de fluides miscibles)* An improved recovery process in which a fluid soluble with oil is injected into an oil reservoir to increase recovery.
Natural Gas Liquids (NGL)	*(Liquides de gaz naturel [LGN])* Those hydrocarbon components recovered from natural gas as liquids. These liquids include, but are not limited to, ethane, propane, butanes, and pentanes.
Nitrous Oxide (N_2O)	*(Oxyde nitreux)* A chemically active gas which has a large number of natural sources and is a secondary product of combustion.
Oil Sands	*(Sables bitumineux)* Deposits of sand or sandstone, or other sedimentary rocks containing bitumen.
Open Access	*(Libre-accès)* The non-discriminatory access to pipelines or electricity transmission lines.
Peak Demand	*(Demande de pointe)* The maximum level of demand over a stated period of time.
Peaking Capacity	*(Capacité de pointe)* Electricity generating equipment which is available to meet peak demand.
Pentanes Plus	*(Pentanes plus)* A mixture mainly of pentanes and heavier hydrocarbons obtained from the processing of raw gas, condensate or crude oil.
Plantgate Price (Gas)	*(Prix après traitement [gaz naturel])* The price received by producers for natural gas delivered to a pipeline system.

Primary Energy Demand	*(Demande d'énergie primaire)* The total requirement for all uses of energy, including energy used by the final consumer, intermediate uses of energy in transforming one energy form to another, and energy used by suppliers in providing energy to the market.
Productive Capacity (or Deliverability)	*(Capacité de production [ou productibilité])* The estimated rate at which natural gas, crude oil or bitumen can be produced, unrestricted by demand but constrained by costs and transportation infrastructure.
Pulping Liquor	*(Liqueur de pâte)* A by-product of the manufacture of chemical pulp which can be used as a fuel.
Raw Natural Gas	*(Gaz naturel brut)* Natural gas as it is produced from the reservoir prior to processing. In addition to marketable natural gas, it contains varying amounts of NGL, water vapour, and other compounds.
Real Price	*(Prix réel)* The price of a commodity after adjusting for inflation. In this report most real prices are expressed in 1997 dollars .
Recovery - Improved (or Enhanced)	*(Récupération assistée)* Recovery through a production process other than primary recovery.
Recovery - Primary	*(Récupération primaire)* The extraction of crude oil or raw natural gas from a reservoir utilizing only its natural energy.
Reserves - Additions	*(Additions aux réserves)* Incremental changes to established reserves resulting from the discovery of new pools.
Reserves - Appreciation	*(Appréciation des réserves)* Change to established reserves resulting from extensions to existing pools or revisions to reserves estimates.
Reserves - Established	*(Réserves établies)* The sum of proven reserves and half of the probable reserves.
Reserves - Initial	*(Réserves initiales)* Reserves prior to deduction of any production.
Reserves - Probable	*(Réserves probables)* The portion of reserves contiguous with proven reserves that are interpreted to exist with reasonable certainty.
Reserves - Proven	*(Réserves prouvées)* Reserves recoverable under current technology and present and anticipated economic conditions, specifically demonstrated by drilling, testing or production.
Reserves - Remaining	*(Réserves restantes)* Initial reserves less cumulative production at a given time.
Reserves to Production Ratio	*(Ratio réserves/production)* Remaining reserves divided by annual production.
Reservoir (or Pool)	*(Gisement [ou réservoir])* A porous and permeable underground rock formation containing a natural accumulation of crude oil or raw natural gas that is confined by impermeable rock or water barriers.
Resources - Discovered	*(Ressources découvertes)* Resources that are estimated to be recoverable using known technology but that have not yet been recognized as established reserves because of uncertain economic viability.

Resources - In Place	*(Ressources en place)* The gross volume of crude oil or raw natural gas estimated to be initially contained in a reservoir, before any volume has been produced and without regard for the extent to which such volumes will be recovered.
Resources - Recoverable	*(Ressources récupérables)* That portion of the ultimate resources potential recoverable under expected economic and technical conditions.
Resources - Ultimate Potential	*(Potentiel ultime de ressources)* An estimate of all the resources that may become recoverable or marketable, having regard for the geological prospects and anticipated technology. It consists of cumulative production, remaining established reserves, discovered resources and undiscovered resources.
Resources - Undiscovered	*(Ressources non découvertes)* Resources that are estimated to be recoverable from accumulations that are believed to exist on the basis of available geological and geophysical evidence, but which have not yet been shown to exist by drilling, testing or production.
Shrinkage	*(Pertes en cours de traitement)* The quantity of raw natural gas removed at field processing plants for recovery of liquids and by-products, removal of impurities, or used as fuel.
Solar Energy	*(Énergie solaire)* Includes active and passive solar heat collection systems and photovoltaics.
Stand Alone Upgrader	*(Usine de valorisation indépendante)* An upgrading facility that is not associated with a mining plant or a refinery.
Straddle Plant	*(Usine de chevauchement)* A natural gas processing plant, located on a main gas transmission system, which extracts NGL from the gas stream.
Supply Cost	*(Coût de l'offre)* Expresses all costs associated with resource exploitation as an average cost per unit of production over the project life. It includes capital costs associated with exploration, development, and production, operating costs, taxes, royalties, and producer return.
Thermal Generation	*(Production thermique)* Energy conversion in which fuel is consumed to generate heat energy which is converted to mechanical energy and then to electricity.
Tight Gas	*(Gaz de réservoir étanche)* Natural gas contained in low permeability reservoirs.
Unconventional Crude Oil	*(Pétrole brut non classique)* Crude oil which is not classified as conventional crude oil (e.g., bitumen).
Unconventional Natural Gas	*(Gaz naturel non classique)* Natural gas which is not classified as conventional natural gas (e.g., coal bed methane).
Upgraded Crude Oil (or Synthetic)	*(Pétrole brut valorisé [ou synthétique])* A mixture of hydrocarbons similar to light crude oil derived by upgrading oil sands bitumen or heavy fuel oil.

APPENDIX 1

Written Submissions

As part of the Round 1 or Round 2 Consultations, the following parties provided the Board with written submissions.

Alberta Energy and Utilities Board
Campaign for Nuclear Phaseout
Canada-Newfoundland Offshore Petroleum Board
Canadian Gas Association
Canadian Gas Potential Committee
Citizens for Renewable Energy
Coal Association of Canada
Consumers' Association of Canada
Dekita International
Energy and Environmental Analysis Inc.
Environment Canada
Foothills Pipe Lines Ltd.
GasEnergy Strategies Inc.
Gaz Métropolitain
Green Alternative Institute of Alberta
Héliojoule
Hydro Québec
Indian and Northern Affairs Canada
Industrial Gas Users Association
Manitoba Hydro
Marenco Energy Associates
Maritimes and Northeast Pipeline and Westcoast Energy Inc.
Montgomery, D.S.
National Council of Women of Canada
Newfoundland Department of Mines and Energy
Nova Scotia Natural Resources
Nova Scotia Power
Nuclear Awareness Project
Ontario Ministry of Energy Science and Technology
Pembina Institute for Appropriate Development
Progas Ltd.
Provincial Council of Women of Ontario
Renewable Energy Options for Canada
Sask Power
Saskatchewan Energy and Mines
Stoian, Eliodor R.Q.
Syncrude Canada Ltd.
TransCanada PipeLines
Vision Quest Windelectric Inc.
Walsh, John H.

LIST OF TABLES

Appendix 2 to Appendix 10

Appendix 2 to Appendix 10 are available in on the Board's Website under Energy Overview at **www.neb.gc.ca.** A list of the Tables presented in these appendices follows Appendix 1.

APPENDIX 8: COAL

APPENDIX 9: SOURCES AND USES OF ENERGY

APPENDIX 10: EMISSIONS OF GREENHOUSE GASES

ABBREVIATION TABLE

Prefixes		Equivalent
k	kilo	10^3
M	mega	10^6
G	giga	10^9
T	tera	10^{12}
P	peta	10^{15}
E	exa	10^{18}

IMPERIAL/METRIC CONVERSION TABLE

Physical Units		Equivalent
m	metre	3.28 feet
m^3	cubic metres	6.3 barrels (oil, LPG)
		35.3 cubic feet (gas)
L	litre	0.22 imperial Gallon
t	metric tonne	2200 pounds
bbl	barrel (oil, LPG)	0.159 m^3

ENERGY CONTENT TABLE

Energy Measures		Energy content
GJ	gigajoule	0.95 million BTU
PJ	petajoules	

Electricity		Energy content
MW	megawatt	
GW.h	gigawatt hour	3600 GJ
TW.h	terawatt hour	3.6 PJ

Natural Gas		Energy content
Mcf	thousand cubic feet	1.05 GJ
Bcf	billion cubic feet	1.05 PJ
Tcf	trillion cubic feet	1.05 EJ

Natural Gas Liquids		Energy content
m^3	Ethane	18.36 GJ
m^3	Propane	25.53 GJ
m^3	Butanes	28.62 GJ

Crude Oil		Energy content
m^3	Light	38.51 GJ
m^3	Heavy	40.90 GJ
m^3	Pentanes Plus	35.17 GJ

Coal		Energy content
t	Anthracite	27.70 GJ
t	Bituminous	27.60 GJ
t	Subbituminous	18.80 GJ
t	Lignite	14.40 GJ

Petroleum Products		Energy content
m^3	Aviation Gasoline	33.52 GJ
m^3	Motor Gasoline	34.66 GJ
m^3	Petrochemical Feedstock	34.17 GJ
m^3	Naphta Specialties	35.17 GJ
m^3	Aviation Turbo Fuel	35.93 GJ
m^3	Kerosene	37.68 GJ
m^3	Diesel	38.68 GJ
m^3	Light Fuel Oil	38.68 GJ
m^3	Lubes and Greases	39.16 GJ
m^3	Heavy Fuel Oil	41.73 GJ
m^3	Still Gas	41.73 GJ
m^3	Asphalt	44.46 GJ
m^3	Petroleum Coke	42.38 GJ
m^3	Other Products	39.82 GJ

Other Fuels		Energy Content
m^3	methanol	15.60 GJ

Canada